Q. Are any of the Fortis companies which are involved in the electricity sector in Canada subject to:

a. Distribution reliability and service standards;

b. An incentive regulatory mechanism?

If so, please file all documentation relating to the standard or regulatory mechanism.

A. *Maritime Electric*

a. Maritime Electric is not subject to distribution reliability and service standards. Maritime Electric provides a monthly report to the Island Regulatory and Appeals Commission on a set of Key Performance Indicators ("KPI"). The KPI report is available to the Commission through a dedicated secure web portal.

b. Maritime Electric is not subject to an incentive regulatory mechanism.

FortisAlberta

a. With the enactment of the *Electric Utilities Act*, S.A. 2003, c. E-5.1 on June 1, 2003, the Alberta Utilities Commission ("AUC") was given the legislative authority to make and enforce rules respecting a limited number of service quality standards.

For more detailed information, please see Attachment A, *Electric Utilities Act*, and Attachment B, *AUC Rule 002*.

b. On September 12, 2012, the AUC issued a decision on the form of Performance Based Regulation ("PBR") to apply to gas and electric distribution companies in Alberta. The AUC anticipates the changes will come into effect on January 1, 2013.

For more detailed information, please see Attachment C, *AUC Rate Regulation Initiative*.

FortisOntario

a. FortisOntario is required by the Ontario Energy Board ("OEB") to report on its performance with respect to its service quality standards. This requirement, which is set out in the *OEB Distribution System Code,* came into effect in January 2009.

For more detailed information, please see Attachment D, *OEB Distribution System Code*, and Attachment E, *OEB Staff Report to the Board, Distribution System Reliability Standards*.

b Rates for FortisOntario are set using a combination of annual incentive regulation mechanism (IRM) adjustments and periodic cost of service reviews.

For more detailed information, please see Attachment F, *Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors, July 14, 2008*, Attachment G, *Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors, September 17, 2008*, Attachment H, *EB-2007-0673, Supplemental Decision on Cost Eligibility* and Attachment I, *Ontario Energy Board Filing Requirements for Electricity Transmission and Distribution Applications*.

This PBR framework is currently under review. For more detailed information, please see Attachment J, *Report of the Board, Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach*.

FortisBC

a. Although PBR regulation of FortisBC ended as of December 31, 2011, FortisBC continues to report to the British Columbia Utilities Commission on its performance.

b. FortisBC is no longer subject to an incentive regulatory mechanism.

Province of Alberta Electric Utilities Act

Province of Alberta

ELECTRIC UTILITIES ACT

Statutes of Alberta, 2003
Chapter E-5.1

Current as of May 13, 2011

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Note

All persons making use of this consolidation are reminded that it has no legislative sanction, that amendments have been embodied for convenience of reference only. The official Statutes and Regulations should be consulted for all purposes of interpreting and applying the law.

Amendments Not in Force

This consolidation incorporates only those amendments in force on the consolidation date shown on the cover. It does not include the following amendments:

2003 cE-5.1 s168 repeals ss156 to 163.

2009 cA-31.5 s36 repeals and substitutes ss10(2)(a)(i) to (iii) 78(2)(a)(i) to (iii).

Regulations

The following is a list of the regulations made under the *Electric Utilities Act* that are filed as Alberta Regulations under the Regulations Act

	Alta. Reg.	*Amendments*
Electric Utilities Act		
Balancing Pool	158/2003	
Billing Regulation, 2003	159/2003	*288/2009*
City of Medicine Hat Payment in Lieu of Tax	235/2003	*105/2005, 68/2008, 175/2008, 288/2009, 31/2012*
Code of Conduct	160/2003	*254/2007*
Common Facilities Costs	161/2003	
Distribution Tariff	162/2003	*6/2004, 254/2007*

ELECTRIC UTILITIES ACT

Chapter E-5.1

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Division 1
Transitional Provisions

HER MAJESTY, by and with the advice and consent of the Legislative Assembly of Alberta, enacts as follows:

Part 1
Interpretation, Application and Purpose

Interpretation

1(1) In this Act,

(a) "affiliated electricity retailer" has the meaning given to it in regulations made by the Minister under section 108;

(a.1) "affiliated gas retailer" has the meaning given to it in regulations made by the Minister under section 108;

(a.2) "affiliated retailer" means an affiliated electricity retailer or an affiliated gas retailer;

(b) "ancillary services" means those services required to ensure that the interconnected electric system is operated in a manner that provides a satisfactory level of service with acceptable levels of voltage and frequency;

(c) "Balancing Pool" means the corporation established by section 75;

(d) "bill" or "billing" means an account for charges arising from the generation, transmission, distribution or sale of electricity;

(e) “Commission” means the Alberta Utilities Commission established by the *Alberta Utilities Commission Act*;

(f) “conduct” includes acts and omissions;

(f.1) “critical transmission infrastructure” means a transmission facility designated under section 41.1 or the Schedule as critical transmission infrastructure;

(g) “Crown” means the Crown in right of Alberta and includes an agent of the Crown;

(h) “customer” means a person purchasing electricity for the person’s own use;

(i) “dispatch” means a direction from the Independent System Operator to a market participant to cause, permit or alter the exchange of electric energy or ancillary services;

(j) “distributed generation” means a generating unit that is interconnected with an electric distribution system;

(k) repealed 2007 cA-37.2 s82(4);

(l) “distribution tariff billing” means an account for electric distribution service provided to a retailer or a regulated rate provider;

(l.1) “electric distribution service” means the service required to transport electricity by means of an electric distribution system

(i) to customers, or

(ii) from distributed generation to the interconnected electric system,

and includes any services the owner of the electric distribution system is required to provide by the Commission or is required to provide under this Act or the regulations, but does not include the provision of electricity services to eligible customers under a regulated rate tariff;

(m) “electric distribution system” means the plant, works, equipment, systems and services necessary to distribute electricity in a service area, but does not include a generating unit or a transmission facility;

(n) “electric energy” means the capability of electricity to do work, measured in kilowatt hours;

(o) "electric utility" means an isolated generating unit, a transmission facility or an electric distribution system that is used

(i) directly or indirectly for the public, or

(ii) to supply electricity to members of an association whose principal object is to supply electricity to its members,

the owner of which

(iii) is required by this Act or the regulations to apply to the Commission for approval of a tariff,

(iv) is permitted by this Act or the regulations to apply to the Commission for approval of a tariff, and has applied for that approval, or

(v) passes a bylaw that has been approved by the Lieutenant Governor in Council under section 138,

but does not include an arrangement of conductors intended to distribute electricity solely on property of which a person is the owner or a tenant, for use solely by that person and solely on that property or a facility exempted by Commission rules made under section 117;

(p) "electricity" means electric energy, electric power, reactive power or any other electromagnetic effects associated with alternating current or high voltage direct current electric systems;

(q) "electricity services" means the services associated with providing electricity to a person, including the following:

(i) the exchange of electric energy;

(ii) making financial arrangements to manage financial risk associated with the pool price;

(iii) electric distribution service;

(iv) system access service;

(v) ancillary services;

(vi) billing;

(vii) metering;

(viii) performing load settlement;

(ix) any other services specified in the regulations made by the Minister under section 115;

(r) “eligible customer” has the meaning given to it in regulations made by the Minister under section 108;

(s) “exchange” means to provide electric energy to or receive electric energy from the interconnected electric system;

(t) “farm transmission costs”, in respect of an owner of an electric distribution system, means

(i) the proportion of the owner’s costs of supplying electricity on 25 000 volt lines to the service area boundaries of rural electrification associations that the total electricity supplied to rural electrification association members within those boundaries for farm and farm irrigation purposes bears to the total electricity supplied on those lines, and

(ii) an equivalent dollar amount per unit of electricity supplied by the electric distribution system to farm and farm irrigation customers who are not members of rural electrification associations;

(u) “generating unit” means the component of a power plant that produces, from any source, electric energy and ancillary services, and includes a share of the following associated facilities that are necessary for the safe, reliable and economic operation of the generating unit, which may be used in common with other generating units:

(i) fuel and fuel handling equipment;

(ii) cooling water facilities;

(iii) switch yards;

(iv) other items;

(v) “hour” means 60 minutes or any period of less than 60 minutes established as an hour in accordance with ISO rules;

(w) “Independent System Operator” means the corporation established by section 7;

(x) "industrial system" has the meaning given to it in the *Hydro and Electric Energy Act*;

(y) "information systems" means systems for the collection, storage and dissemination of data that identify individual customer consumption of electricity from the interconnected electric system;

(z) "interconnected electric system" means all transmission facilities and all electric distribution systems in Alberta that are interconnected, but does not include an electric distribution system or a transmission facility within the service area of the City of Medicine Hat or a subsidiary of the City, unless the City passes a bylaw that is approved by the Lieutenant Governor in Council under section 138;

(aa) "interval meter" means a meter that

(i) measures, at intervals of 60 minutes or less, the amount of electricity consumed, and

(ii) satisfies the standards for revenue collection under the *Electricity and Gas Inspection Act* (Canada) and the *Weights and Measures Act* (Canada);

(bb) "isolated generating unit" means a generating unit that is determined to be an isolated generating unit in accordance with the regulations made by the Minister under section 99;

(cc) "load settlement" means the process of determining the hourly consumption of electric energy of each customer in Alberta and providing that information to the Independent System Operator, retailers and regulated rate providers in order to identify responsibility for purchases of electric energy exchanged through the power pool;

(dd) "market" means any type of market through or under which an offer, purchase, sale, trade or exchange of electricity, electric energy, electricity services or ancillary services takes place in relation to the production or consumption of electricity, electric energy, electricity services or ancillary services;

(ee) "market participant" means

(i) any person that supplies, generates, transmits, distributes, trades, exchanges, purchases or sells electricity, electric energy, electricity services or ancillary services, or

(ii) any broker, brokerage or forward exchange that trades or facilitates the trading of electricity, electric energy, electricity services or ancillary services;

(ff) “Market Surveillance Administrator” means the corporation continued by section 32 of the *Alberta Utilities Commission Act*;

(gg) “metering” means the purchase, installation, operation and reading of a meter that measures and records the amount of electricity that flows through a particular point;

(hh) “Minister” means the Minister determined under section 16 of the *Government Organization Act* as the Minister responsible for this Act;

(ii) “municipality” means a city, town, village, summer village, municipal district or specialized municipality, a town under the *Parks Towns Act* or a municipality formed by special Act, and includes a Metis settlement established under the *Metis Settlements Act*;

(jj) “owner”, in respect of a generating unit, a transmission facility or an electric distribution system, means the owner, operator, manager or lessee of that unit, facility or system, or any person who is acting as an agent for the owner, operator, manager or lessee, and in the event that one of those persons becomes bankrupt or insolvent, includes any trustee, liquidator or receiver appointed in respect of the bankruptcy or insolvency;

(kk) “person” includes an individual, unincorporated entity, partnership, association, corporation, trustee, executor, administrator or legal representative;

(ll) “pool price” means the price for each hour established and reported by the Independent System Operator, in accordance with the ISO rules, for electric energy exchanged through the power pool;

(mm) “power pool” means the scheme operated by the Independent System Operator for

(i) exchange of electric energy, and

(ii) financial settlement for the exchange of electric energy;

(nn) "power purchase arrangement" means a power purchase arrangement included in Alberta Regulation AR 175/2000, but does not include

(i) the power purchase arrangement that applies to the H.R. Milner generating unit;

(ii) the power purchase arrangement that applies to the Sturgeon generating units;

(iii) a power purchase arrangement that expires in accordance with the unit effective term completion date specified in the power purchase arrangement;

(iv) a power purchase arrangement that is terminated under section 15.2 of the power purchase arrangement;

(v) a power purchase arrangement that is terminated by the Balancing Pool;

(oo) "rate classification customer" has the meaning given to it in regulations made by the Minister under section 108 or in a regulated rate tariff;

(pp) "rates" means prices, rates, tolls and charges;

(qq) "regulated rate provider" means the owner of an electric distribution system, or a person authorized by the owner that provides electricity services to eligible customers in the owner's service area under a regulated rate tariff;

(rr) "record" includes

(i) information or data regardless of its physical form or characteristics;

(ii) information or data in a form that can produce sound, with or without a visual form;

(iii) information or data in electronic, magnetic or mechanical storage;

(iv) electronic data transmission signals;

(v) any other thing that is capable of being represented or reproduced visually or by sound, or both;

(vi) anything in which information or data is stored, including software and any mechanism or device that produces the information or data;

(ss) "regulations" means

(i) regulations made under this Act;

(ii) Alberta Regulation AR 175/2000;

(iii) regulations continued under this Act by a regulation made by the Minister under section 154;

(ss.1) "reliability standards" means the reliability standards made under section 142(1)(l.1);

(tt) "retail electricity services" means electricity services provided directly to a customer but does not include electricity services provided to eligible customers under a regulated rate tariff;

(uu) "retailer" means a person who sells or provides retail electricity services and includes an affiliated retailer;

(vv) "rural electrification association" means an association under the *Rural Utilities Act* that has as its principal object the supply of electricity to its members;

(ww) "service area" means the area determined under the *Hydro and Electric Energy Act* from time to time in which

(i) the owner of an electric distribution system may distribute electricity, or

(ii) a rural electrification association may distribute electricity to its members;

(xx) "service area of the municipality" means the service area for the electric distribution system owned by a municipality or a subsidiary of a municipality;

(yy) "system access service" means the service obtained by market participants through a connection to the transmission system, and includes access to exchange electric energy and ancillary services;

(zz) "tariff" means a document that sets out

(i) rates, and

(ii) terms and conditions;

(aaa) "terms and conditions", in respect of a tariff, means the standards, classifications, regulations, practices, measures and terms and conditions that apply to services provided under the tariff;

(bbb) "transmission facility" means an arrangement of conductors and transformation equipment that transmits electricity from the high voltage terminal of the generation transformer to the low voltage terminal of the step down transformer operating phase to phase at a nominal high voltage level of more than 25 000 volts to a nominal low voltage level of 25 000 volts or less, and includes

(i) transmission lines energized in excess of 25 000 volts,

(ii) insulating and supporting structures,

(iii) substations, transformers and switchgear,

(iv) operational, telecommunication and control devices,

(v) all property of any kind used for the purpose of, or in connection with, the operation of the transmission facility, including all equipment in a substation used to transmit electric energy from

(A) the low voltage terminal,

to

(B) electric distribution system lines that exit the substation and are energized at 25 000 volts or less,

and

(vi) connections with electric systems in jurisdictions bordering Alberta,

but does not include a generating unit or an electric distribution system;

(ccc) "transmission system" means all transmission facilities in Alberta that are part of the interconnected electric system.

(ddd) repealed 2007 cA-37.2 s82(4).

(2) A reference in this Act to

(a) "ISO bylaws" means bylaws made by the Independent System Operator under section 10;

(b) “ISO fees” means the fees established by the Independent System Operator under section 21;

(c) “ISO order” means an order made by the Independent System Operator under section 22;

(d) “ISO rules” means the rules made by the Independent System Operator under section 19 or 20;

(e) “ISO tariff” means the tariff prepared by the Independent System Operator under section 30 that has been approved by the Commission.

(3) For the purpose of determining whether a corporation is a subsidiary of another corporation under this Act or the regulations, section 2(4) of the *Business Corporations Act* applies.

(4) For the purposes of this Act, the “service area of the City of Medicine Hat” or “service area of the City” means

(a) the service area for the electric distribution system owned by the City of Medicine Hat or a subsidiary of the City on the date this section comes into force and includes any subsequent amendments made in accordance with section 29 of the *Hydro and Electric Energy Act*,

(b) any transmission facilities owned by the City of Medicine Hat or a subsidiary of the City that are located outside the City’s service area described in clause (a) and that are used to provide electric distribution service to customers within the City’s service area described in clause (a),

(c) any plant, works, equipment and systems owned by the City of Medicine Hat or a subsidiary of the City that are located outside the City’s service area described in clause (a) and that are used to provide electric distribution service to customers within the City’s service area described in clause (a),

(d) any properties located outside the City’s service area described in clause (a) to which the City or a subsidiary of the City provides electric distribution service on the date this section comes into force, and any plant, works, equipment, systems and services necessary to provide electric distribution service to those properties, and

(e) any properties to which the City of Medicine Hat or a subsidiary of the City is authorized to provide electric distribution service pursuant to an approval by the Commission under section 26 of the *Hydro and Electric*

Energy Act, and any plant, works, equipment and systems owned by the City of Medicine Hat or a subsidiary of the City necessary to serve those properties.

2003 cE-5.1 s1;2007 cA-37.2 s82(4);2009 c44 s2

Exemptions from the Act

2(1) This Act does not apply to

(a) electric energy produced in the service area of the City of Medicine Hat

(i) by the City or a subsidiary of the City and consumed in that service area, or

(ii) by generating units that produce electric energy under contract to the City or to a subsidiary of the City and consumed in that service area,

unless the City passes a bylaw that is approved by the Lieutenant Governor in Council under section 138;

(b) electric energy produced on property of which a person is the owner or a tenant, and consumed solely by that person and solely on that property;

(c) electric energy produced by the following generating units located in the City of Calgary, to the extent of the capacity of those units on January 1, 1996:

(i) Glenmore water treatment facility;

(ii) Bearspaw water treatment facility;

(iii) Turbo Expander;

(d) electric energy exempted by the Commission in accordance with rules made under section 117.

(2) The exemptions under subsection (1)(a) and sections 37(2)(a), 100, 109 and 153(1) do not apply if the City of Medicine Hat or a subsidiary of the City does not provide the information or statements required by a regulation made under section 142(1)(h).

(3) The exemption under subsection (1)(b) applies whether or not the owner or tenant is the owner of the generating unit producing the electric energy.

2003 cE-5.1 s2;2007 cA-37.2 s82(4)

Effect of the Act

3(1) Nothing in this Act requires

(a) any person to transfer or divest itself of any property owned by it, or

(b) any change in the boundaries of the service area of an electric distribution system.

(2) Agreements existing when this Act or any portion of this Act or any Act that amends this Act comes into force relating to the generation, transmission, distribution, offer, purchase, sale, trade or exchange of electricity are preserved unless subsection (3) applies.

(3) An agreement existing when this Act or any portion of this Act or any Act that amends this Act comes into force and that is expressly or by necessary implication inconsistent with this Act or the Act that amends this Act is deemed to be amended to the extent necessary to make the agreement consistent with this Act or the Act that amends this Act.

Immunity for the Crown

4 No action may be brought against the Crown claiming compensation for any real or perceived loss or damage resulting from the coming into force or the implementation of

(a) the *Electric Utilities Act*, SA 1995 cE-5.5, the *Electric Utilities Amendment Act*, *1998*, SA 1998 c13, or the *Electric Utilities Act*, RSA 2000 cE-5, or any regulations made under those Acts, or

(b) this Act or amendments to this Act or any regulations made or purported to be made under those Acts.

Purposes of the Act

5 The purposes of this Act are

(a) to provide an efficient Alberta electric industry structure including independent, separate corporations to carry out the responsibilities of the Independent System Operator and the Balancing Pool, and to set out the powers and duties of those corporations;

(b) to provide for a competitive power pool so that an efficient market for electricity based on fair and open competition can develop, where all persons wishing to exchange electric energy through the power pool may do so on non-discriminatory terms and may make financial arrangements to manage financial risk associated with the pool price;

(c) to provide for rules so that an efficient market for electricity based on fair and open competition can develop in which neither the market nor the structure of the Alberta electric industry is distorted by unfair advantages of government-owned participants or any other participant;

(d) to continue a flexible framework so that decisions of the electric industry about the need for and investment in generation of electricity are guided by competitive market forces;

(e) to enable customers to choose from a range of services in the Alberta electric industry, including a flow-through of pool price and other options developed by a competitive market, and to receive satisfactory service;

(f) to continue the sharing, among all customers of electricity in Alberta, of the benefits and costs associated with the Balancing Pool;

(g) to continue the framework established for power purchase arrangements;

(h) to provide for a framework so that the Alberta electric industry can, where necessary, be effectively regulated in a manner that minimizes the cost of regulation and provides incentives for efficiency.

2003 cE-5.1 s5;2007 cA-37.2 s82(4)

Expectations of market participants

6 Market participants are to conduct themselves in a manner that supports the fair, efficient and openly competitive operation of the market.

Part 2
Independent System Operator and Transmission

Division 1
Corporate Organization

ISO established

7(1) There is hereby established a corporation to be known as the Independent System Operator.

(2) The Independent System Operator consists of its members, who are appointed under section 8.

(3) The Independent System Operator is not a Provincial corporation for the purposes of the *Financial Administration Act*, the *Auditor General Act* or any other enactment.

(4) For the purposes of the *Government Accountability Act*, the Independent System Operator is not part of the ministry, as defined in that Act, of any Minister of the Government of Alberta.

(5) The Independent System Operator is not an agent of the Crown.

Appointment of ISO members

8(1) The Minister must appoint as members of the Independent System Operator not more than 9 individuals who, in the opinion of the Minister,

(a) are independent of any person who has a material interest in the Alberta electric industry, and

(b) will enhance the performance of the Independent System Operator in exercising its powers and carrying out its duties, responsibilities and functions.

(2) The Minister must designate one of the members of the Independent System Operator as chair.

(3) In accordance with ISO bylaws, the members of the Independent System Operator

(a) must recommend to the Minister individuals to be appointed as members for all appointments after the appointment of the first members, and

(b) may recommend to the Minister an individual to be designated as chair when a chair needs to be designated.

(4) The members of the Independent System Operator must oversee the business and affairs of the Independent System Operator.

(5) The term of office of a member is for not more than 3 years.

(6) A member is eligible to be appointed for not more than 3 terms of office.

(7) A member continues to hold office after the expiry of the member's term until the member is reappointed, the member's successor is appointed or a period of 3 months has elapsed, whichever occurs first.

(8) A member is eligible to receive the reasonable remuneration and expenses set out in the ISO bylaws.

(9) In carrying out any duty, responsibility or function as a member of the Independent System Operator, the member must

(a) act honestly, in good faith and in the public interest,

(b) avoid conflicts of interest, and

(c) exercise the care, diligence and skill that a reasonably prudent individual would exercise in comparable circumstances.

Natural person powers

9(1) Subject to this Act and the regulations, the Independent System Operator has the rights, powers and privileges of a natural person.

(2) Except when the power to delegate is restricted by this Act, by regulations made under section 41 or 142 or by ISO bylaws, the Independent System Operator may delegate any power or duty conferred or imposed on it under this or any other enactment

(a) to any of the members, officers or employees of the Independent System Operator, or

(b) to any other qualified person the Independent System Operator considers appropriate.

(3) The Independent System Operator shall not delegate the power to approve annual financial statements or its power to make bylaws.

(4) The Independent System Operator shall not, without the consent of the Minister, delegate any of its powers, duties, responsibilities or functions to a regional transmission organization or enter into any agreement that has that effect.

(5) The Independent System Operator may enter into arrangements or agreements with responsible authorities in jurisdictions outside Alberta respecting the operations, standards and business practices relating to the interconnected electric system

(a) in Alberta, or

(b) in conjunction with the operation of electric systems outside Alberta.

(6) The Independent System Operator may not own or hold an interest in any transmission facility, electric distribution system or generating unit.

Bylaws

10(1) The Independent System Operator must make bylaws governing its business and affairs.

(2) In its bylaws, the Independent System Operator

(a) must establish

(i) a code of conduct for its members, officers, employees and agents,

(ii) criteria and a process for recommending the appointment of members and designation of an individual as chair when an appointment or designation is needed,

(iii) the reasonable remuneration and expenses members are eligible to receive, and

(iv) criteria relating to the removal of members and the process to be followed to recommend to the Minister the removal of a member,

and

(b) may establish

(i) the number of its members that constitutes a quorum at meetings of the Independent System Operator, and

(ii) rules respecting the number of its members that is required to carry out any decision in order for that decision to bind all of its members and to constitute a decision of the Independent System Operator.

(3) The Independent System Operator must make its bylaws available to the public.

Chief executive officer

11 The Independent System Operator must appoint a qualified individual to act as its chief executive officer.

Auditor

12 The Independent System Operator must appoint an independent auditor to review and audit its financial statements.

13 Repealed 2007 cA-37.2 s82(4).

ISO budget

14(1) The Independent System Operator must prepare a budget for each fiscal year setting out

(a) the estimated expenditures, costs and expenses of the Independent System Operator to carry out its powers, duties, responsibilities and functions, which may include expenditures for capital assets allocated over the expected useful life of the asset,

(b) the aggregate estimated expenditures, costs and expenses in the approved budget of the Market Surveillance Administrator,

(c) its estimated revenue from ISO fees, and

(d) its estimated revenue from the ISO tariff.

(2) The Independent System Operator may amend its budget.

(3) The Independent System Operator must be managed so that, on an annual basis, no profit or loss results from its operation.

Reporting

15(1) The Independent System Operator must, within 120 days after the end of its fiscal year, provide to the Minister an annual report

(a) reporting on its business and affairs in the fiscal year, and

(b) containing its audited financial statements for the fiscal year.

(2) After providing the annual report to the Minister, the Independent System Operator must make it available to the public.

(3) The Independent System Operator must provide to the Minister any other reports and information relating to its duties, responsibilities and functions that the Minister requests.

Division 2
Independent System Operator Duties and Authority

Duty to act responsibly

16 The Independent System Operator must exercise its powers and carry out its duties, responsibilities and functions in a timely manner that is fair and responsible to provide for the safe, reliable and economic operation of the interconnected electric system and to promote a fair, efficient and openly competitive market for electricity.

ALSA regional plans

16.1 In carrying out its mandate under this Act and other enactments, the Independent System Operator must act in accordance with any applicable ALSA regional plan.

2009 cA-26.8 s74

Duties of Independent System Operator

17 The Independent System Operator has the following duties:

(a) to operate the power pool in a manner that promotes the fair, efficient and openly competitive exchange of electric energy;

(b) to facilitate the operation of markets for electric energy in a manner that is fair and open and that gives all market participants wishing to participate in those markets and to exchange electric energy a reasonable opportunity to do so;

(c) to determine, according to relative economic merit, the order of dispatch of electric energy and ancillary services in Alberta and from scheduled exchanges of electric energy and ancillary services between the interconnected electric system in Alberta and electric systems outside Alberta, to satisfy the requirements for electricity in Alberta;

(d) to carry out financial settlement for all electric energy exchanged through the power pool at the pool price unless this Act or the regulations made by the Minister under section 41 provide otherwise;

(e) to manage and recover the costs of transmission line losses;

(f) to manage and recover the costs for the provision of ancillary services;

(g) to provide system access service on the transmission system and to prepare an ISO tariff;

(h) to direct the safe, reliable and economic operation of the interconnected electric system;

(i) to assess the current and future needs of market participants and plan the capability of the transmission system to meet those needs;

(j) to make arrangements for the expansion of and enhancement to the transmission system;

(k) to collect, store and disseminate information relating to the current and future electricity needs of Alberta and the capacity of the interconnected electric system to meet those needs, and make that information available to the public;

(l) to administer load settlement;

(l.1) to monitor the compliance of market participants with rules made under sections 19, 20 and 24.1;

(m) to perform any other function or engage in any activity the Independent System Operator considers necessary or advisable to exercise its powers and carry out its duties, responsibilities and functions under this Act and regulations.

2003 cE-5.1 s17;2007 cA-37.2 s82(4)

Power pool

18(1) The Independent System Operator must operate the power pool in a manner that is fair, efficient and open to all market participants exchanging or wishing to exchange electric energy through the power pool and that gives all market participants a reasonable opportunity to do so.

(2) All electric energy entering or leaving the interconnected electric system must be exchanged through the power pool unless regulations made under section 41, section 99 or section 142 provide otherwise.

(3) A person shall not intentionally cause or permit electric energy or ancillary services to enter or leave the interconnected electric system except in accordance with ISO rules.

(4) The Independent System Operator must establish and report the pool price, which shall not include any portion of the ISO fees, and make the hourly pool price available to the public.

Direct sales agreements and forward contracts

19(1) In this section,

(a) "direct sales agreement" means an agreement relating to the sale or purchase of electric energy in accordance with the terms agreed to by the parties to the agreement, but does not include a forward contract;

(b) "forward contract" means an agreement relating to the sale or purchase of electric energy

(i) that is tradeable on a forward exchange, and

(ii) that provides for the future delivery of electric energy;

(c) "forward exchange" means an organization that is in the business of operating a market for buying and selling forward contracts.

(2) Exchange of electric energy under a direct sales agreement or a forward contract must be undertaken in accordance with ISO rules, including rules

(a) setting out the requirements, including the information to be provided to the Independent System Operator, concerning a direct sales agreement or forward contract,

(b) authorizing persons other than the Independent System Operator to make financial settlement for electric energy sold or purchased under a direct sales agreement or forward contract,

(c) authorizing that financial settlement may be at a price other than the pool price for electric energy sold or purchased under a direct sales agreement or forward contract, and

(d) relating to the curtailment and certainty of supply of electric energy sold or purchased under a direct sales agreement or forward contract.

(3) A rule under subsection (2) shall not require a person buying or selling electric energy under a direct sales agreement or forward contract to disclose to the Independent System Operator information relating to the price of electric energy sold or purchased under the agreement or contract.

ISO rules

20(1) The Independent System Operator may make rules respecting

(a) the practices and procedures of the Independent System Operator;

(b) the operation of the power pool and the exchange of electric energy through the power pool;

(c) the operation of the interconnected electric system;

(d) the provision of ancillary services;

(e) planning the transmission system, including criteria and standards for the reliability and adequacy of the transmission system;

(f) the processes for expansion and enhancement of the transmission system;

(g) the procedures to be observed in emergencies relating to the operation of the interconnected electric system;

(h) repealed 2007 cA-37.2 s82(4);

(i) direct sales agreements and forward contracts as defined in section 19(1);

(j) the granting of exemptions from the rules, and setting out the process for obtaining an exemption;

(k) procedures for resolving disputes between the Independent System Operator and market participants, which may include arbitration under the *Arbitration Act*;

(l) any other matter the Independent System Operator considers necessary or advisable to carry out its duties, responsibilities and functions under this Act and the regulations.

(2), **(3)** Repealed 2007 cA-37.2 s82(4).

2003 cE-5.1 s20;2007 cA-37.2 s82(4)

Application

20.1 Sections 20.2 to 20.5 do not apply to an ISO rule

(a) that was made before the coming into force of those sections, or

(b) that takes effect in accordance with section 20.6.

2007 cA-37.2 s82(4)

Filing of ISO rules

20.2(1) The Independent System Operator must file with the Commission an ISO rule made under section 19 or 20.

(2) The Commission must publish notice of the filing of an ISO rule under subsection (1) not later than 5 days after the day of filing.

(3) Subject to subsection (4), a notice under subsection (2) must include a copy of the ISO rule or set out where a copy may be obtained.

(4) If the Commission is satisfied on information provided by the Independent System Operator that it would not be in the public interest for an ISO rule to be available to the public, the notice under subsection (2) must contain a summary of the ISO rule and explain why a copy of the ISO rule is not included.

2007 cA-37.2 s82(4)

Effective date of ISO rules

20.3 Except as otherwise provided by section 20.6,

(a) if no notice of objection is filed under section 20.4, the ISO rule takes effect on the later of the day specified in the ISO rule and the 10th day after the day on which notice of the ISO rule is published, or

(b) if a notice of objection is filed under section 20.4,

(i) where the ISO rule is confirmed, the ISO rule takes effect on the latest of

(A) the day on which an order is made confirming the ISO rule,

(B) the day specified in the ISO rule, and

(C) the day otherwise ordered by the Commission,

or

(ii) where the ISO rule is changed pursuant to an order under section 20.5(1)(c), the ISO rule takes effect in accordance with section 20.5(4).

2007 cA-37.2 s82(4)

Objection to ISO rule

20.4(1) A market participant may object to an ISO rule that is filed under section 20.2 on one or more of the following grounds:

(a) that the Independent System Operator, in making the ISO rule, did not comply with Commission rules made under section 20.9;

(b) that the ISO rule is technically deficient;

(c) that the ISO rule does not support the fair, efficient and openly competitive operation of the market;

(d) that the ISO rule is not in the public interest.

(1.1) The Market Surveillance Administrator may object to an ISO rule that is filed under section 20.2 on one or more of the following grounds:

(a) that the ISO rule may have an adverse effect on the structure and performance of the market;

(b) a ground set out in subsection (1)(c) or (d).

(2) A notice of objection must be filed with the Commission within 10 days after publication of the notice of the filing of the ISO rule.

(3) Where a market participant files a notice of objection, the market participant has the onus of proving

(a) that the Independent System Operator, in making the ISO rule, did not comply with Commission rules made under section 20.9,

(b) that the ISO rule is technically deficient,

(c) that the ISO rule does not support the fair, efficient and openly competitive operation of the market, or

(d) that the ISO rule is not in the public interest.

(4) Where the Market Surveillance Administrator files a notice of objection, the Market Surveillance Administrator has the onus of proving

(a) that the ISO rule may have an adverse effect on the structure and performance of the market,

(b) that the ISO rule does not support the fair, efficient and openly competitive operation of the market, or

(c) that the ISO rule is not in the public interest.

2007 cA-37.2 s82(4);2011 c11 s3

Commission decision

20.5(1) The Commission may, after hearing an objection, by order

(a) confirm the ISO rule,

(b) disallow the ISO rule, or

(c) direct the Independent System Operator to change the ISO rule or a provision of the ISO rule.

(2) The Independent System Operator must file an ISO rule that is changed pursuant to an order under subsection (1)(c) with the Commission.

(3) The Commission must publish notice of the filing of an ISO rule under subsection (2) as soon as possible and not later than 5 days after the day of filing.

(4) An ISO rule that is filed under subsection (2) comes into effect on the latest of

(a) the day on which it is filed,

(b) the day specified in the ISO rule, and

(c) the day otherwise ordered by the Commission.

2007 cA-37.2 s82(4)

Expedited ISO rule

20.6(1) If, in the opinion of the Independent System Operator, a matter that is addressed in an ISO rule is urgent or there are other sufficient reasons that require that the ISO rule take effect expeditiously, the Independent System Operator may specify in the ISO rule that it takes effect in accordance with this section.

(2) The Independent System Operator must file an ISO rule referred to in subsection (1) with the Commission.

(3) An ISO rule that is filed under subsection (2) takes effect on the later of the day on which it is filed and the day specified in the ISO rule.

(4) The Commission must publish notice of an ISO rule that is filed under subsection (2) as soon as possible and not later than 5 days after the day of filing.

2007 cA-37.2 s82(4)

Availability of ISO rules

20.7(1) Subject to subsection (2), the Independent System Operator must make available to the public an ISO rule that is in effect.

(2) If the Commission is satisfied on information provided by the Independent System Operator that it would not be in the public interest for an ISO rule to be available to the public, the Independent System Operator must make available to the public a summary of the ISO rule that contains an explanation as to why the ISO rule is not being made available.

2007 cA-37.2 s82(4)

Duty to comply with ISO rules and reliability standards

20.8 A market participant must comply with

(a) the ISO rules that are in effect, and

(b) the reliability standards.

2007 cA-37.2 s82(4);2009 c44 s2

Commission rules

20.9 The Commission may make rules governing the procedures and processes that the Independent System Operator may use to develop ISO rules and respecting the filing of ISO rules.

2007 cA-37.2 s82(4)

ISO fees

21(1) The Independent System Operator must establish and charge fees payable by market participants

(a) for the exchange of electric energy through the power pool,

(b) to pay for the aggregate expenditures, costs and expenses shown in the approved budget of the Market Surveillance Administrator and any approved amendment to the budget, and

(c) to pay for the costs and expenses of other powers, duties, responsibilities and functions of the Independent System Operator, except costs and expenses recovered under the ISO tariff.

(2) The fees must be just and reasonable and may be varied from time to time.

(3) A market participant who is charged a fee by the Independent System Operator must pay the fee.

(4) A market participant charged a fee by the Independent System Operator may make a complaint to the Commission under section 25.

(5) A fee charged by the Independent System Operator is a debt owing by the market participant to the Independent System Operator and in default of payment may be recovered by the Independent System Operator by an action in debt.

(6) The Independent System Operator must maintain a current schedule of its fees and make the schedule available to the public.

2003 cE-5.1 s21;2007 cA-37.2 s82(4)

Contravention of ISO rule

21.1 Except as otherwise provided by the regulations, if the Independent System Operator suspects that a market participant has contravened an ISO rule or a reliability standard, the Independent System Operator must refer the matter to the Market Surveillance Administrator.

2007 cA-37.2 s82(4);2009 c44 s2

Failure to pay ISO fee

22(1) If a market participant fails to pay an ISO fee, the Independent System Operator may refer the matter to the Commission.

(2) If the Commission is satisfied that a market participant has failed to pay an ISO fee, the Commission may order the market participant to pay the ISO fee and may impose an administrative penalty on the market participant under section 63 of the *Alberta Utilities Commission Act*.

2003 cE-5.1 s22;2007 cA-37.2 s82(4)

23 and **24** Repealed 2007 cA-37.2 s82(4).

Load settlement rules

24.1(1) The Commission may make rules respecting load settlement, including rules respecting

(a) the conduct of load settlement by market participants,

(b) the establishment of processes, procedures, standards, reports and controls required to determine the hourly allocation of electric energy to sites and to customers,

(c) the determination, collection and storage of site, metering and other data in order to provide necessary measurement data,

(d) the development and use of customer load profiles to determine the hourly allocation of electric energy to sites that do not have interval meters,

(e) the transfer of data among market participants,

(f) the payment to the Commission of professional and other costs relating to the development and implementation of the rules and by whom the costs are to be paid,

(g) incentives for efficient performance of load settlement, and

(h) any other matter the Commission considers necessary and advisable relating to load settlement.

(2) The Independent System Operator must administer load settlement in accordance with the rules made under subsection (1).

(3) A market participant must comply with rules made by the Commission under subsection (1).

(4) On referral by the Independent System Operator, on application or on its own initiative, the Commission may determine whether a market participant is complying with the rules respecting load settlement.

(5) If the Commission is of the opinion that a market participant has failed or is failing to comply with the rules respecting load settlement, the Commission may by order do all or any of the following:

(a) direct the market participant to comply with the rules or to take any action to improve load settlement that the Commission considers just and reasonable;

(b) direct the market participant to pay or provide a credit in an amount specified by the Commission to a person determined by the Commission who has suffered loss or damage resulting from the failure of the market participant to comply with the rules to compensate that person;

(c) prohibit the market participant from engaging in any activity or conduct that the Commission considers to be detrimental to load settlement;

(d) impose an administrative penalty under section 63 of the *Alberta Utilities Commission Act*.

2007 cA-37.2 s82(4)

Division 3
Recourse to the Commission

Complaints to the Commission

25(1) A market participant may make a written complaint to the Commission

(a) about an ISO fee, or

(b) about an ISO rule that is in effect, on one or more of the following grounds:

(i) that the ISO rule is technically deficient;

(ii) that the ISO rule does not support the fair, efficient and openly competitive operation of the market;

(iii) that the ISO rule is not in the public interest.

(1.1) The Market Surveillance Administrator may make a written complaint to the Commission about an ISO rule that is in effect on one or more of the following grounds:

(a) that the ISO rule may have an adverse effect on the structure and performance of the market;

(b) a ground set out in subsection (1)(b)(ii) or (iii).

(2) A complaint about an ISO fee must be made within 60 days after the day on which the market participant receives notice of the fee.

(3) Repealed 2011 c11 s3.

(4) The Commission may decline to hold a hearing or other proceeding if, in the opinion of the Commission,

(a) the complaint is frivolous, vexatious, trivial or otherwise does not warrant a hearing or other proceeding, or

(b) the complaint or the substance of it has been referred to, should be referred to, or is the subject of investigation by, the Market Surveillance Administrator.

(4.1) Where a market participant files a complaint, the market participant has the onus of proving

(a) that the ISO rule is technically deficient,

(b) that the ISO rule does not support the fair, efficient and openly competitive operation of the market, or

(c) that the ISO rule is not in the public interest.

(4.11) Where the Market Surveillance Administrator files a complaint, the Market Surveillance Administrator has the onus of proving

(a) that the ISO rule may have an adverse effect on the structure and performance of the market,

(b) that the ISO rule does not support the fair, efficient and openly competitive operation of the market, or

(c) that the ISO rule is not in the public interest.

(4.2) The Commission must decline to hold a hearing or other proceeding if, in the opinion of the Commission, the complaint or the substance of it relates to the Independent System Operator's compliance with the Commission rules made under section 20.9 in making the ISO rule.

(5) Unless the Commission otherwise orders, a complaint under this section does not relieve the person making the complaint from the obligation

(a) to pay an ISO fee pending a decision of the Commission, or

(b) to comply with an ISO order or ISO rule pending a decision of the Commission.

(6) The Commission may, after hearing a complaint, by order,

(a) determine the justness and reasonableness of the ISO fee and confirm, change or revoke the fee,

(b) direct the Independent System Operator to reimburse a market participant any fee paid to the Independent System Operator,

(c) confirm the ISO rule,

(d) disallow the ISO rule, or

(e) direct the Independent System Operator to change the ISO rule or a provision of the ISO rule.

(7) The Independent System Operator must file with the Commission an ISO rule that is changed pursuant to an order under subsection (6)(e).

(8) The Commission must publish notice of the filing of an ISO rule under subsection (7) as soon as possible and not later than 5 days after the day of filing.

(9) A change to an ISO rule filed under subsection (7) comes into effect on the latest of

(a) the day on which it is filed,

(b) the day specified in the ISO rule, and

(c) the day otherwise ordered by the Commission.

2003 cE-5.1 s25;2007 cA-37.2 s82(4);2011 c11 s3

Complaints about ISO

26(1) Any person may make a written complaint to the Commission about the conduct of the Independent System Operator.

(2) The Commission must dismiss the complaint, giving reasons for the dismissal, if the Commission is satisfied that

(a) the substance of the complaint has been or should be referred to the Market Surveillance Administrator for investigation,

(b) the complaint relates to a matter the substance of which is before or has been dealt with by the Commission or any other body, or

(c) the complaint is frivolous, vexatious or trivial or otherwise does not warrant an investigation or a hearing.

(3) The Commission may, in considering a complaint, do one or more of the following:

(a) dismiss all or part of the complaint;

(b) direct the Independent System Operator to change its conduct in relation to a matter that is the subject of the complaint;

(c) direct the Independent System Operator to refrain from the conduct that is the subject of the complaint.

(4) A decision of the Commission under subsection (2) or (3) is final and may not be appealed under section 29 of the *Alberta Utilities Commission Act*.

2003 cE-5.1 s26;2007 cA-37.2 s82(4)

Security measures

27 The Independent System Operator may develop plans and implement measures for the purpose of ensuring that the Independent System Operator is able to exercise its powers and carry out its duties, responsibilities and functions in a manner that is secure against the threat of terrorist activity as that term is defined in the *Criminal Code* (Canada).

Division 4
Transmission Responsibilities of the Independent System Operator

ISO sole provider of system access service

28 The Independent System Operator is the sole provider of system access service on the transmission system.

Providing system access service

29 The Independent System Operator must provide system access service on the transmission system in a manner that gives all market participants wishing to exchange electric energy and ancillary services a reasonable opportunity to do so.

ISO tariff

30(1) The Independent System Operator must submit to the Commission, for approval under Part 9, a single tariff setting out

(a) the rates to be charged by the Independent System Operator for each class of system access service, and

(b) the terms and conditions that apply to each class of system access service provided by the Independent System Operator to persons connected to the transmission system.

(2) The rates to be charged by the Independent System Operator for each class of service must reflect the prudent costs that are reasonably attributable to each class of system access service provided by the Independent System Operator, and the rates must

(a) be sufficient to recover

(i) the amounts to be paid under the approved tariff of the owner of each transmission facility,

(ii) the amounts to be paid to the owner of a generating unit in circumstances in which the Independent System Operator directs that a generating unit must continue to operate, and the costs to make prudent arrangements to manage the financial risk associated with those amounts,

(iii) farm transmission costs, and

(iv) any other prudent costs and expenses the Commission considers appropriate,

(b) either be sufficient to recover the annualized amount paid to the Balancing Pool under section 82(7), or if the Independent System Operator receives an annualized amount under section 82(7), reflect that amount, and

(c) include any other costs, expenses and revenue determined in accordance with the regulations made by the Minister under section 99.

(3) The rates set out in the tariff

(a) shall not be different for owners of electric distribution systems, customers who are industrial systems or a person who has made an arrangement under section 101(2) as a result of the location of those systems or persons on the transmission system, and

(b) are not unjust or unreasonable simply because they comply with clause (a).

(4) The Independent System Operator may recover the costs of transmission line losses and the costs of arranging provision of ancillary services acquired from market participants by

(a) including either or both of those costs in the tariff, in addition to the amounts and costs described in subsection (2), in which case the Commission must include in the tariff the additional costs it considers to be prudent, or

(b) establishing and charging ISO fees for either or both of those costs.

2003 cE-5.1 s30;2007 cA-37.2 s82(4)

Duty to comply with ISO tariff

31 A market participant who obtains system access service must

(a) pay the Independent System Operator the rates prescribed in the ISO tariff, and

(b) comply with the terms and conditions of the tariff.

Payments by ISO

32 The Independent System Operator must

(a) pay the rates set out in the approved tariff of the owner of each transmission facility;

(b) pay incremental generation costs that are owing to the owner of a generating unit if the Independent System Operator directs that a generating unit must continue to operate, and make prudent arrangements to manage the financial risk associated with those costs;

(c) pay farm transmission costs;

(d) pay isolated generation costs determined in accordance with the regulations made by the Minister under section 99;

(e) pay or collect the annualized amount in accordance with section 82(7);

(f) pay the prudent costs for other services acquired from a market participant related to the provision of system access service.

Transmission system planning

33(1) The Independent System Operator must forecast the needs of Alberta and develop plans for the transmission system to provide efficient, reliable and non-discriminatory system access service and the timely implementation of required transmission system expansions and enhancements.

(2) In developing plans under subsection (1), the Independent System Operator must consult on the plans, in accordance with the regulations, before completing the preparation of the plans.

(3) The Independent System Operator must provide to the Minister, in accordance with the regulations, the plans completed by it under subsection (1).

2003 cE-5.1 s33;2007 cA-37.2 s82(4);2009 c44 s2

Alleviation of constraints or other conditions on transmission system

34(1) When the Independent System Operator determines that an expansion or enhancement of the capability of the transmission system is or may be required to meet the needs of Alberta and is in the public interest, the Independent System Operator must prepare and submit to the Commission for approval a needs identification document that

(a) describes the constraint or condition affecting the operation or performance of the transmission system and indicates the means by which or the manner in which the constraint or condition could be alleviated,

(b) describes a need for improved efficiency of the transmission system, including means to reduce losses on the interconnected electric system, or

(c) describes a need to respond to requests for system access service.

(2) On its own initiative or in response to views expressed by the Commission, the Independent System Operator may amend a needs identification document submitted to the Commission for approval.

(3) The Commission may, subject to the regulations,

(a) approve the needs identification document,

(b) refer the needs identification document back to the Independent System Operator with directions or suggestions for changes or additions, or

(c) refuse to approve the needs identification document.

2003 cE-5.1 s34;2007 cA-37.2 s82(4)

Transmission facilities directions and proposals

35(1) The Independent System Operator may, at the time of preparing a needs identification document, after submitting a needs identification document to the Commission or after receiving Commission approval of a needs identification document,

(a) direct the owner of a transmission facility to submit, for Commission approval under the *Hydro and Electric Energy Act*, a transmission facility proposal to meet the need identified, or

(b) request market participants to submit, for approval by the Independent System Operator, a proposal to meet the need identified.

(2) The owner of a transmission facility must comply with a direction from the Independent System Operator under subsection (1) unless the owner gives written notice to the Independent System Operator, giving reasons, that

(a) a real and substantial risk of damage to its transmission facility could result if the direction were complied with,

(b) a real and substantial risk to the safety of its employees or the public could result if the direction were complied with, or

(c) a real and substantial risk of undue injury to the environment could result if the direction were complied with.

(3) Subject to subsection (2), on receiving a direction the owner of a transmission facility must prepare an application to meet the requirements or objectives of the direction and apply to the

Commission for approval under the *Hydro and Electric Energy Act*.

2003 cE-5.1 s35;2007 cA-37.2 s82(4)

Other proposals to alleviate transmission constraints

36(1) On receipt of a proposal by a market participant to meet a need identified in the needs identification document, the Independent System Operator may

(a) approve the proposal, with or without conditions or modification, or

(b) refuse the proposal.

(2) The Independent System Operator may specify the time within which the person who obtains approval of a proposal must apply to the Commission for approval under the *Hydro and Electric Energy Act*, if approval is required under that Act.

2003 cE-5.1 s36;2007 cA-37.2 s82(4)

Transmission facility owner's tariff

37(1) Each owner of a transmission facility must submit to the Commission for approval a tariff setting out the rates to be paid by the Independent System Operator to the owner for the use of the owner's transmission facility.

(2) Subsection (1) does not apply to

(a) the City of Medicine Hat with respect to transmission facilities in the service area of the City, or

(b) the owners of transmission facilities to which section 153 applies during the period that the rates referred to in section 153 have effect.

2003 cE-5.1 s37;2007 cA-37.2 s82(4)

Joint tariff

38 One or more owners of transmission facilities may agree with the Independent System Operator to prepare and submit to the Commission for approval one joint tariff that sets out the rates and terms and conditions applicable to the Independent System Operator and the owner.

2003 cE-5.1 s38;2007 cA-37.2 s82(4)

Duties of transmission facility owners

39(1) Each owner of a transmission facility must operate and maintain the transmission facility in a manner that is consistent with the safe, reliable and economic operation of the interconnected electric system.

(2) Each owner of a transmission facility must, in a timely manner, assist the Independent System Operator in any manner to enable the Independent System Operator to carry out its duties, responsibilities and functions.

(3) Each owner of a transmission facility must

(a) establish, in conjunction with owners of electric distribution systems, procedures and systems for load shedding in emergencies;

(b) provide the Independent System Operator in a timely manner with descriptions, ratings and operating restrictions relating to their transmission facility;

(c) inform the Independent System Operator in a timely manner of anticipated changes in their transmission facility that could affect the Independent System Operator in carrying out its duties, responsibilities and functions, including

(i) the capability of the transmission facility,

(ii) the status and availability of the transmission facility, including maintenance schedules, and

(iii) additions to, alterations to or decommissioning of transmission facilities or any part of them;

(c.1) install and remove meters and perform metering, including verifying meter readings and verifying accuracy of meters that are directly connected to the owner's transmission facility;

(d) comply with standards and practices established by the Independent System Operator to enable the Independent System Operator to carry out its duties, responsibilities and functions;

(e) provide the Independent System Operator with use of the owner's transmission facility for the purpose of carrying out the Independent System Operator's duties, responsibilities and functions.

(4) The owner of a transmission facility may refuse to comply with a direction from the Independent System Operator only if the owner notifies the Independent System Operator that the owner considers that

(a) a real and substantial risk of damage to its transmission facility could result if the direction were complied with;

(b) a real and substantial risk to the safety of its employees or the public could result if the direction were complied with;

(c) a real and substantial risk of undue injury to the environment could result if the direction were complied with.

2003 cE-5.1 s39;2007 cA-37.2 s82(4)

Industrial systems

40(1) Each owner of an industrial system must assist the Independent System Operator to enable the Independent System Operator to carry out its duties, responsibilities and functions.

(2) If, after taking into account the needs of the owner of an industrial system and the capability of the industrial system, the Independent System Operator is satisfied that transmission facilities of an industrial system are required to be used for system access service, the Independent System Operator may apply to the Commission for an order.

(3) If the Commission is satisfied

(a) access to an industrial system is required to meet the needs or anticipated needs to provide system access service, and

(b) the needs of the owner of the industrial system, including the capability and reliability of the owner's system, will continue to be met,

the Commission, by order, may grant access to the industrial system and, if so, may establish the rates, and terms and conditions under which the access is provided, or amend existing terms and conditions of the owner under this Act or the *Hydro and Electric Energy Act*.

2003 cE-5.1 s40;2007 cA-37.2 s82(4)

Regulations

41 The Minister may make regulations

(a) adding to, clarifying, limiting or restricting any of the Independent System Operator's powers, duties, responsibilities and functions, or regulating how they are to be exercised;

(b) respecting exemptions from the requirement set out in section 17(d) or 18(2).

Part 2.1
Critical Transmission Infrastructure

Designation of critical transmission infrastructure

41.1(1) The Lieutenant Governor in Council may designate as critical transmission infrastructure a proposed transmission facility if it is contained in a plan that is prepared by the Independent System Operator pursuant to this Act or the regulations and if the transmission facility

(a) is an intertie,

(b) is to serve areas of renewable energy,

(c) is a double circuit transmission facility that is designed to be energized at a nominal voltage of 240 000 volts,

(d) is designed to be energized at a voltage in excess of 240 000 volts, or

(e) is, in the opinion of the Lieutenant Governor in Council, critical to ensure the safe, reliable and economic operation of the interconnected electric system.

(2) An order under subsection (1)

(a) must for each transmission facility designated as critical transmission infrastructure

(i) describe the technical solution, which may include voltage, transmission capacity expressed in megawatts and alternating current or direct current,

(ii) that is linear in nature, describe the approximate geographic starting point and the approximate geographic end point of the critical transmission infrastructure,

(iii) that is not linear in nature, describe the approximate geographic area of the location of the critical transmission infrastructure, and

(iv) contain or address any matters required by the regulations made under section 142,

(b) may vary from the description of the proposed transmission facility contained in the plan prepared by the Independent System Operator referred to in subsection (1), and

(c) may contain any other matter that the Lieutenant Governor in Council considers necessary.

2009 c44 s2

Non-application of ss34 to 36

41.2 Sections 34, 35 and 36 do not apply to critical transmission infrastructure.

2009 c44 s2

Direction to apply

41.3 Subject to the regulations and an order under section 41.1(1), the Independent System Operator must, in a timely manner, direct a person determined under the regulations to make an application in a timely manner to the Commission under the *Hydro and Electric Energy Act* for an approval of critical transmission infrastructure.

2009 c44 s2

Staged development of CTI referred to in Schedule

41.4(1) The Independent System Operator, with respect to the critical transmission infrastructure referred to in section 1(1) of the Schedule, shall, subject to the regulations, specify and make available to the public milestones that the Independent System Operator will use to determine the timing of the stages of the expansion of the terminals referred to in section 1(1)(a) and (b) of the Schedule.

(2) The transmission facilities referred to in section 4 of the Schedule shall be developed in stages in accordance with subsection (3).

(3) The facility referred to in section 4(a) of the Schedule shall be developed first, which may initially be energized at 240 kV, and the Independent System Operator shall, subject to the regulations, specify and make available to the public milestones that the Independent System Operator will use to determine the timing of the development of the facilities referred to in section 4(b) and (c) of the Schedule.

2009 c44 s2

Part 3 Repealed 2007 cA-37.2 s82(4).

Part 4
Balancing Pool

Division 1
Corporate Organization

Balancing Pool established

75(1) There is hereby established a corporation to be known as the Balancing Pool.

(2) The Balancing Pool consists of its members, who are appointed under section 76.

(3) The Balancing Pool is not a Provincial corporation for the purposes of the *Financial Administration Act*, the *Auditor General Act* or any other enactment.

(4) For the purposes of the *Government Accountability Act*, the Balancing Pool is not part of the ministry, as defined in that Act, of any Minister of the Government of Alberta.

(5) The Balancing Pool is not an agent of the Crown.

Appointment of Balancing Pool members

76(1) The Minister must appoint as members of the Balancing Pool not more than 9 individuals who, in the opinion of the Minister,

(a) are independent of any person who has a material interest in the Alberta electric industry, and

(b) will enhance the performance of the Balancing Pool in exercising its powers and carrying out its duties, responsibilities and functions.

(2) The Minister must designate one of the members of the Balancing Pool as chair.

(3) In accordance with Balancing Pool bylaws, the members of the Balancing Pool

(a) must recommend to the Minister individuals to be appointed as members for all appointments after the appointment of the first members, and

(b) may recommend to the Minister an individual to be designated as chair when a chair needs to be designated.

(4) The members of the Balancing Pool must oversee the business and affairs of the Balancing Pool.

(5) The term of office of a member is for not more than 3 years.

(6) A member is eligible to be appointed for not more than 3 terms of office.

(7) A member continues to hold office after the expiry of the member's term of office until the member is reappointed, the member's successor is appointed or a period of 3 months has elapsed, whichever first occurs.

(8) A member is eligible to receive the reasonable remuneration and expenses set out in the Balancing Pool bylaws.

(9) In carrying out any duty, responsibility or function as a member of the Balancing Pool, the member must

(a) act honestly and in good faith,

(b) avoid conflicts of interest, and

(c) exercise the care, diligence and skill that a reasonably prudent individual would exercise in comparable circumstances.

Natural person powers

77(1) Subject to this Act and the regulations, the Balancing Pool has the rights, powers and privileges of a natural person.

(2) Except when the power to delegate is restricted by this Act, by regulations made under section 88 or 142 or by Balancing Pool bylaws, the Balancing Pool may delegate any power or duty conferred or imposed on it under this or any other enactment

(a) to any of the members, officers or employees of the Balancing Pool, or

(b) to any other qualified person the Balancing Pool considers appropriate.

(3) The Balancing Pool shall not delegate the power to approve annual financial statements or its power to make bylaws.

Bylaws

78(1) The Balancing Pool must make bylaws governing its business and affairs.

(2) In its bylaws the Balancing Pool

(a) must establish

(i) a code of conduct for its members, officers, employees and agents,

(ii) criteria and a process for recommending the appointment of members and designation of an individual as chair when an appointment or designation is needed,

(iii) the reasonable remuneration and expenses Balancing Pool members are eligible to receive, and

(iv) criteria relating to the removal of members and the process to be followed to recommend to the Minister the removal of a member,

and

(b) may establish

(i) the number of its members that constitutes a quorum at meetings of the Balancing Pool, and

(ii) rules respecting the number of its members that is required to carry out any decision in order for that decision to bind all of its members and to constitute a decision of the Balancing Pool.

(3) The Balancing Pool must make its bylaws available to the public.

Chief executive officer

79 The Balancing Pool must appoint a qualified individual to act as its chief executive officer.

Auditor

80 The Balancing Pool must appoint an independent auditor to review and audit its financial statements.

Committees

81 If the Balancing Pool establishes a committee to consult with market participants or other persons, it must

(a) set up a process for appointing individuals to the committee,

(b) describe the committee's mandate, and

(c) specify the reasonable remuneration and expenses members of the committee are eligible to be paid for committee work.

Budget

82(1) The Balancing Pool must prepare a budget for each fiscal year setting out the estimated revenues and expenses of the Balancing Pool to carry out its powers, duties, responsibilities and functions, which may include expenditures for capital assets allocated over the useful life of the asset.

(2) The Balancing Pool may amend its budget.

(3) The Balancing Pool, in establishing or amending its budget, must forecast its revenues and expenses and include an annualized amount.

(4) The Balancing Pool must notify the Independent System Operator of the annualized amount for each fiscal year.

(5) On receiving notice of the annualized amount, the Independent System Operator must include that amount in its tariff in accordance with section 30(2).

(6) The Commission must

(a) approve the annualized amount provided to the Independent System Operator by the Balancing Pool, without modification, and

(b) approve, with or without modification, the allocation of the annualized amount to the owners of electric distribution systems, industrial systems and persons that have made arrangements under section 101(2).

(7) The Balancing Pool and the Independent System Operator must co-operate in determining the appropriate timing and methodology of transferring the annualized amount

(a) to the Independent System Operator from the Balancing Pool, if the amount is a positive amount, or

(b) from the Independent System Operator to the Balancing Pool, if the amount is a negative amount.

(8) If in respect of any year the Independent System Operator and the Balancing Pool fail to agree on the timing and methodology of transferring the annualized amount, that amount must be transferred by the Independent System Operator to the Balancing Pool in equal monthly instalments.

(9) In this section, "annualized amount" means annualized amount as defined in or calculated under the regulations made under section 88.

2003 cE-5.1 s82;2007 cA-37.2 s82(4);2009 c44 s2

Balancing Pool investments

83(1) The Balancing Pool must follow prudent investment standards in making investment decisions relating to and in managing the balancing pool accounts.

(2) A prudent investment standard is a standard that, in the overall context of an investment portfolio, a reasonably prudent person would apply to investments made on behalf of another person with whom there exists a fiduciary relationship to make such investments without undue risk of loss or impairment and with a reasonable expectation of fair return or appreciation.

Records and reporting

84 The Balancing Pool must

(a) maintain accounting records and a record of its business and affairs,

(b) within 120 days after the end of its fiscal year, prepare and have audited financial statements of the balancing pool accounts in the preceding fiscal year,

(c) at any time when required to do so by the Minister, prepare and have audited financial statements relating to any part of its business and affairs for any period of time specified by the Minister,

(d) after the end of each fiscal year, provide the Minister a report containing

(i) its audited financial statements, and

(ii) a summary of the activities of the Balancing Pool relating to the balancing pool accounts in the year,

and

(e) make the report provided to the Minister available to the public.

Division 2
Balancing Pool Duties

Balancing Pool duties

85(1) The Balancing Pool has the following duties:

(a) to establish or continue one or more accounts which together are to be known as the balancing pool accounts;

(b) to manage generation assets in a commercial manner during the period the Balancing Pool holds generation assets;

(c) to organize the management of generation assets in a manner that is in keeping with the eligibility requirements for a person to hold a power purchase arrangement or an agreement or arrangement derived from a power purchase arrangement in accordance with the regulations made by the Minister under section 99;

(d) to sell generation assets when, in the opinion of the Balancing Pool, market conditions are such that a competitive sale of the assets will result in the Balancing Pool receiving fair market value for the generation assets;

(e) to continue to hold the hydro power purchase arrangement and manage the payments associated with that power purchase arrangement;

(f) to participate in regulatory, dispute resolution and other proceedings and processes if, in the opinion of the Balancing Pool, it is necessary or advisable to do so in order to protect the interests of the Balancing Pool and the value of the Balancing Pool's assets;

(g) to manage risks prudently in all aspects of the Balancing Pool's operations;

(h) to ensure, in accordance with the regulations made under section 88, that any net amount in the balancing pool accounts that is greater than \$0 or less than \$0 is included in the ISO tariff;

(i) to oversee payments into or out of the balancing pool accounts in accordance with this Act and the regulations;

(j) to manage the balancing pool accounts so that no profit or loss results, after accounting for the annualized amount under section 82(7) as a revenue or expense of the Balancing Pool;

(k) to carry out any other function or duty given to it under the regulations.

(2) In this section, "generation assets" means

(a) power purchase arrangements held by the Balancing Pool that include the right to exchange electric energy and ancillary services, and

(b) agreements or arrangements derived from power purchase arrangements held by the Balancing Pool that include the right to exchange electric energy and ancillary services.

2003 cE-5.1s85;2009 c44 s2

Duty to act responsibly

86 The Balancing Pool must exercise its powers and carry out its duties in a manner that is responsible and efficient.

Division 3
Regulations

87 Repealed 2009 c44 s2.

Regulations

88 The Minister may make regulations

(a) respecting payments into and out of the balancing pool accounts and who is to make or receive the payments;

(a.1) defining "annualized amount" or determining how it is to be calculated;

(b) adding to, clarifying, limiting or restricting any of the Balancing Pool's powers, duties, responsibilities and functions or regulating how they are to be exercised.

(c) repealed 2009 c44 s2.

2003 cE-5.1 s88;2009 c44 s2

Part 5
Liability

Definition

89 In this Part, "affiliate" has the meaning given to it in the *Business Corporations Act*.

Liability protection of ISO

90(1) In this section,

(a) "direct loss or damage" does not include loss of profits, loss of revenue, loss of production, loss of earnings, loss of contract or any other indirect, special or consequential loss or damage whatsoever arising out of or in any way connected with an Independent System Operator act;

(b) "Independent System Operator act" means any act or omission carried out or purportedly carried out by an Independent System Operator person in exercising its powers and carrying out its duties, responsibilities and functions under this Act and the regulations;

(c) "Independent System Operator person" means

(i) the Independent System Operator,

(ii) each member of the Independent System Operator,

(iii) each officer and employee of the Independent System Operator,

(iv) each agent or contractor of the Independent System Operator, and

(v) each affiliate of a person referred to in subclause (iv).

(2) No action lies against an Independent System Operator person, and an Independent System Operator person is not liable, for an Independent System Operator act.

(3) Subsection (2) does not apply

(a) where an Independent System Operator act is carried out by an Independent System Operator person that is not an individual, if the act constitutes wilful misconduct, negligence or breach of contract, or

(b) where an Independent System Operator act is carried out by an Independent System Operator person who is an individual, if the act is not carried out in good faith.

(4) Where, as a result of the operation of subsection (3), an Independent System Operator person is liable to another person for an Independent System Operator act, the Independent System Operator person is liable only for direct loss or damage suffered or incurred by that other person.

(5) In addition to any other indemnity the Independent System Operator may provide, where

(a) legal action has been commenced against an Independent System Operator person for an Independent System Operator act, and

(b) the Independent System Operator person is, as a result of the operation of subsection (2) or otherwise, not liable,

the Independent System Operator must indemnify that Independent System Operator person for, and pay to that Independent System Operator person, all of that Independent System Operator person's costs of defending the legal action, including all reasonable legal expenses and legal fees as between solicitor and client, and the amounts so paid to or on behalf of that Independent System Operator person are recoverable by the Independent System Operator in accordance with subsection (6).

(6) The amounts paid to or on behalf of an Independent System Operator person under subsection (5) may be recovered by the Independent System Operator through ISO fees established under section 21.

2003 cE-5.1 s90;2009 c53 s54

91 Repealed 2007 cA-37.2 s82(4).

Liability protection of Balancing Pool

92(1) In this section,

(a) "balancing pool person" means

(i) the Balancing Pool,

(ii) each member of the Balancing Pool,

(iii) each officer and employee of the Balancing Pool,

(iv) each agent or contractor of the Balancing Pool, and

(v) each affiliate of a person referred to in subclause (iv);

(b) "balancing pool person act" means any act or omission carried out or purportedly carried out by a balancing pool person in exercising its powers and carrying out its duties, responsibilities and functions under this Act and the regulations;

(c) "direct loss or damage" does not include loss of profits, loss of revenue, loss of production, loss of earnings, loss of contract or any other indirect, special or consequential loss or damage whatsoever arising out of or in any way connected with a balancing pool act.

(2) No action lies against a balancing pool person, and a balancing pool person is not liable, for a balancing pool person act.

(3) Subsection (2) does not apply

(a) where a balancing pool person act is carried out by a balancing pool person that is not an individual, if the act constitutes wilful misconduct, negligence or breach of contract, or

(b) where a balancing pool person act is carried out by a balancing pool person who is an individual, if the act is not carried out in good faith.

(4) Where, as a result of the operation of subsection (3), a balancing pool person is liable to another person for a balancing pool person act, the balancing pool person is liable only for direct loss or damage suffered or incurred by that other person.

(5) In addition to any other indemnity the Balancing Pool may provide, where

(a) a legal action has been commenced against a balancing pool person for a balancing pool person act, and

(b) the balancing pool person is, as a result of the operation of subsection (2) or otherwise, not liable, the Balancing Pool must indemnify that balancing pool person for, and pay to that balancing pool person, all of that balancing pool person's costs of defending the legal action, including all reasonable legal expenses and legal fees as between solicitor and client, and the amounts so paid to or on behalf of that balancing pool person are recoverable by the Balancing Pool in accordance with subsection (6).

(6) The amounts paid to or on behalf of a balancing pool person under subsection (5) may be recovered by the Balancing Pool from the Independent System Operator through a budget or amended budget established under section 82.

2003 cE-5.1 s92;2009 c53 s54

Liability protection for independent assessment team

93(1) No action may be brought against the independent assessment team or any member of it, and the independent assessment team and each member of it are not liable, for any real or perceived loss or damage resulting from any determination made by the independent assessment team or from the implementation of any determination made by the independent assessment team under Part 4.1 of the *Electric Utilities Act*, SA 1995 cE-5.5, and the *Electric Utilities Act*, RSA 2000 cE-5.

(2) In this section, "independent assessment team" means the independent assessment team established by the Minister under Part 4.1 of the *Electric Utilities Act*, SA 1995 cE-5.5, and the *Electric Utilities Act*, RSA 2000 cE-5.

Regulations

94 The Lieutenant Governor in Council may make regulations

(a) protecting any person named in the regulations from the legal liability specified in the regulations in the circumstances and in the manner described in the regulations;

(b) prohibiting, limiting or restricting any cause of action for the purposes of clause (a);

(c) requiring a person named or described in the regulations to indemnify any other person named or described in the regulations to the extent and in the circumstances described in the regulations;

(d) providing immunity from a legal action described in the regulations for persons named or described in the regulations in respect of acts or omissions described in the regulations;

(e) limiting or restricting the nature of damages or loss that a person named or described in the regulations may recover in action from any other person named or described in the regulations;

(f) requiring the Commission to take into consideration, when considering a tariff, or to impose as part of the terms and conditions of a tariff, any of the matters described or referred to in clauses (a) to (e).

2003 cE-5.1 s94;2007 cA-37.2 s82(4)

Part 6
Generation

Permissible municipal interests in generating units

95(1) No municipality and no subsidiary of a municipality may hold, directly or indirectly, an interest in a generating unit except in accordance with any or all of the provisions of this section and the regulations.

(2) If a municipality or a subsidiary of a municipality had an interest in a generating unit on May 1, 1995, that municipality or subsidiary may continue to hold that interest after May 1, 1995 if the generating capacity of the unit does not increase significantly beyond its capacity on that date.

(3) If

(a) a municipality had an interest in a generating unit on May 1, 1995, and

(b) a subsidiary of the municipality acquires the interest after May 1, 1995,

the municipality and the subsidiary are considered to be in compliance with subsection (2) if the generating capacity of the generating unit does not increase significantly beyond its capacity on May 1, 1995.

(4) The City of Medicine Hat or a subsidiary of the City may hold an interest in a generating unit if the generating capacity of that unit and all other generating units in which the City or a subsidiary of the City has an interest does not exceed the capacity that is needed to reliably meet the requirements of customers in the service area of the City.

(5) The Commission must determine whether

(a) a proposal by the City of Medicine Hat or a subsidiary of the City to hold an interest in a generating unit, or

(b) an interest in a generating unit that is held by the City of Medicine Hat or a subsidiary of the City

is in accordance with subsection (4).

(6) Before making a determination under subsection (5), the Commission must obtain an independent assessment about whether the proposal to hold an interest in a generating unit or whether the interest in a generating unit is in accordance with subsection (4).

(7) The City of Medicine Hat or a subsidiary of the City cannot acquire an interest in a generating unit under subsection (4) during any period that the City or a subsidiary of the City does not provide the information or statements required by a regulation made under section 142(1)(h).

(8) A municipality or a subsidiary of a municipality may hold an interest in a generating unit located within the boundaries of the municipality if the generating unit is part of a process that is carried out on property of which the municipality or subsidiary is the owner or tenant and the electric energy produced by the unit is incidental to the main purpose of that process.

(9) A municipality or a subsidiary of a municipality may hold an interest in a generating unit located within the boundaries of the municipality on property of which the municipality or subsidiary is the owner or tenant if a majority of the electric energy produced annually by the unit is used by the municipality or subsidiary on that property.

(10) A municipality or a subsidiary of a municipality may, with the authorization of the Minister, hold an interest in a generating unit if the arrangement under which the interest is held is structured in a manner that prevents any tax advantage, subsidy or financing advantage or any other direct or indirect benefit as a result of association with the municipality or subsidiary.

(11) The Minister must establish procedures to obtain an independent assessment about whether a proposal by a municipality or a subsidiary of a municipality to hold an interest in a generating unit under subsection (10) is in accordance with that subsection.

(12) If the independent assessment concludes that a proposal by a municipality or a subsidiary of a municipality to hold an interest in a generating unit under subsection (10) is in accordance with that subsection, the Minister must give an authorization.

(13) The Minister may establish procedures to facilitate the resolution of any dispute under this section, except those dealt with by the Commission under subsections (4) to (6), about whether an interest or a proposed interest of a municipality or a subsidiary of a municipality in a generating unit is in accordance with this section.

2003 cE-5.1 s95;2007 cA-37.2 s82(4)

Continuation of power purchase arrangements

96(1) A power purchase arrangement continues to have effect in accordance with its terms and conditions, subject to this Act and the regulations.

(2) A power purchase arrangement held by the balancing pool administrator immediately before the coming into force of this section continues to be held by the Balancing Pool in the capacity of a buyer for all purposes of this Act, the regulations and the power purchase arrangement.

(3) A power purchase arrangement, other than a power purchase arrangement held by the Balancing Pool, that is terminated other than under section 15.2 of the power purchase arrangement

(a) is deemed to have been sold to the Balancing Pool, and

(b) is to be held by the Balancing Pool in the capacity of a buyer for all purposes of this Act, the regulations and the power purchase arrangement.

Termination of power purchase arrangement by the Balancing Pool

97 The Balancing Pool may, notwithstanding the terms and conditions of a power purchase arrangement held by the Balancing Pool under section 96(2) and (3), terminate the power purchase arrangement if the Balancing Pool

(a) consults with representatives of customers and the Minister about the reasonableness of the termination,

(b) gives to the owner of the generating unit to which the power purchase arrangement applies 6 months' notice, or any shorter period agreed to by the owner, of its intention to terminate, and

(c) pays the owner or ensures that the owner receives an amount equal to the remaining closing net book value of the generating unit, determined in accordance with the power purchase arrangement, as if the generating unit had been destroyed, less any insurance proceeds.

Power purchase arrangement ceases to apply

98 A power purchase arrangement ceases to apply to a generating unit

(a) on the expiration of the power purchase arrangement in accordance with the unit effective term completion date specified in the power purchase arrangement,

(b) on the termination of the power purchase arrangement under section 15.2 of the power purchase arrangement, or

(c) on the termination of the power purchase arrangement by the Balancing Pool.

Regulations

99 The Minister may make regulations

(a) respecting the payment of an amount into the Balancing Pool by the owner of a generating unit that is

(i) constructed at a power plant, and

(ii) designed to use the facilities identified as associated facilities in Schedule A of a power purchase arrangement;

(b) respecting flare gas generating units, including specifying which provisions of this Act and the regulations do not apply to flare gas generating units and the information the owners or operators of a flare gas generating unit must provide to the Independent System Operator;

(b.1) respecting micro-generation generating units, including, without limitation, regulations

(i) defining “micro-generation generating unit”,

(ii) respecting the development, connection and operation of micro-generation generating units, and

(iii) specifying which provisions of this Act and the regulations do not apply to micro-generation generating units;

(b.2) setting out circumstances, in addition to those set out in section 95, in which a municipality may hold an interest in a generating unit;

(b.3) respecting any matter relating to a municipality holding an interest in a generating unit, including providing for approvals or other requirements necessary for a municipality to hold such an interest;

(c) respecting the eligibility of a person to hold a power purchase arrangement or a contract, agreement or arrangement derived from a power purchase arrangement and prohibiting a person from holding a power purchase arrangement or an agreement or arrangement derived from a power purchase arrangement;

(d) respecting the holding and sale of a power purchase arrangement or agreements or arrangements derived from a power purchase arrangement by the Balancing Pool;

(e) respecting the deletion, suspension, addition or replacement of one or more provisions of a power purchase arrangement when a power purchase arrangement is held by the Balancing Pool;

(f) respecting the duty of an owner of a generating unit to which a power purchase arrangement applies to provide information, including confidential information, to the Balancing Pool for the purpose of the sale of that power purchase arrangement or an agreement or arrangement derived from that power purchase arrangement by the Balancing Pool;

(g) respecting the approval of the Commission of decommissioning costs and the amounts to be collected from customers, or through a power purchase arrangement by the owner of a generating unit to which a power purchase arrangement applies, for the purpose of decommissioning the generating unit, including payment to be made to or to be received from the Balancing Pool;

(h) respecting the determination and treatment of isolated generating units, including the preparation of tariffs related to those units and who is to make or receive payments relating to those units;

(i) respecting the requirement for customer choice in areas not served by the interconnected electric system, including payments to be made to the Independent System Operator by retailers and owners of electric distribution systems in respect of those areas and customers;

(j) respecting the payments into or out of the Balancing Pool related to the *Small Power Research and Development Act*;

(k) respecting the amendment of Alberta Regulation AR 175/2000 in order to continue a power purchase arrangement that applies to more than one generating unit as power purchase arrangements that will apply to one or more of those generating units.

2003 cE-5.1 s99;2007 cA-37.2 s82(4)

Part 7
Distribution

Medicine Hat

100 Nothing in this Part applies

(a) to the electric distribution system owned by the City of Medicine Hat or a subsidiary of the City in the service area of the City, or

(b) to customers whose property is located in the service area of the City of Medicine Hat,

unless the City of Medicine Hat or a subsidiary of the City

(c) has an affiliated retailer that provides retail electricity services outside the service area of the City, or

(d) provides electric distribution service outside the service area of the City.

2003 cE-5.1 s100;2007 cA-37.2 s82(4)

Owner's right to provide electric distribution service

101(1) A person wishing to obtain electricity for use on property must make arrangements for the purchase of electric distribution service from the owner of the electric distribution system in whose service area the property is located.

(2) If the person has an interval meter and receives electricity directly from the transmission system, the person may, with the prior approval of

(a) the owner of the electric distribution system in whose service area the person's property is located, if any, and

(b) the Independent System Operator,

enter into an arrangement directly with the Independent System Operator for the provision of system access service.

(3) No person other than the owner of an electric distribution system may provide electric distribution service on the electric distribution system of that owner.

2003 cE-5.1 s101;2007 cA-37.2 s82(4)

Distribution tariff

102(1) Each owner of an electric distribution system must prepare a distribution tariff for the purpose of recovering the prudent costs of providing electric distribution service by means of the owner's electric distribution system.

(2) The owner of the electric distribution system must apply for approval of its distribution tariff

(a) to the Commission,

(b) to the council of a municipality, if the owner is a municipality or a subsidiary of a municipality

(i) that does not have an affiliated retailer that provides retail electricity services outside the service area of the municipality, and

(ii) that does not provide electric distribution service outside the service area of the municipality either on its own behalf or on behalf of another owner,

or

(c) to the board of directors of the association, if the owner is a rural electrification association.

(3) A distribution tariff of an owner of an electric distribution system that is a municipality or a subsidiary of a municipality

(a) that has an affiliated retailer that provides retail electricity services outside the service area of the municipality, or

(b) that provides electric distribution service outside the service area of the municipality, either on its own behalf or on behalf of another owner, takes effect as of January 1, 2004.

(4) A distribution tariff must be prepared in accordance with the regulations made by the Minister under section 108.

2003 cE-5.1 s102;2007 cA-37.2 s82(4)

Regulated rate tariff

103(1) Each owner of an electric distribution system must prepare a regulated rate tariff for the purpose of recovering the prudent costs of providing electricity services to eligible customers.

(2) The owner must apply for approval of its regulated rate tariff to the Commission unless subsection (3) or (4) applies.

(3) If the owner is a municipality or a subsidiary of a municipality that does not have an affiliated retailer that provides retail electricity services outside the service area of the municipality, the owner may apply to the council of the municipality for approval of the regulated rate tariff.

(4) If the owner is a rural electrification association that does not have an affiliated retailer that provides retail electricity services to customers who are not members of a rural electrification association, the owner may apply to the board of directors of the association for approval of the regulated rate tariff.

(5) Despite subsections (3) and (4), the owner must apply to the Commission if required to do so by the regulations made by the Lieutenant Governor in Council under section 142(1)(j).

(6) Repealed 2007 cA-37.2 s82(4).

(7) The charge for electric energy set out in the regulated rate tariff must be determined in accordance with the regulations made by the Minister under section 108.

(8) The owner may recover in its regulated rate tariff its prudent billing costs of

(a) distribution tariff billing for the regulated rate, and

(b) billing to eligible customers for the regulated rate tariff, including taxes and municipal charges.

(9) If an eligible customer who is in the service area of the owner's electric distribution system is not enrolled with a retailer, the owner is the customer's regulated rate provider and the customer is deemed to have elected to purchase electricity services under that owner's regulated rate tariff.

2003 cE-5.1 s103;2007 cA-37.2 s82(4)

Ongoing obligation of owner of electric distribution systems

104(1) An owner of an electric distribution system may make arrangements under which other persons perform any or all of the duties or functions of the owner under this Act and the regulations.

(2) No arrangement under subsection (1) affects or reduces the responsibility or liability of the owner to carry out those duties or functions.

Duties of owners of electric distribution systems

105(1) The owner of an electric distribution system has the following duties:

(a) to provide electric distribution service that is not unduly discriminatory;

(b) to make decisions about building, upgrading and improving the electric distribution system for the purpose of providing safe, reliable and economic delivery of electric energy having regard to managing losses of electric energy to customers in the service area served by the electric distribution system;

(c) to operate and maintain the electric distribution system in a safe and reliable manner;

(d) if a transmission facility serves only one service area, to arrange for the provision of system access service to customers in that service area, other than customers referred to in section 101(2);

(e) to install and remove meters and perform metering, including verifying meter readings and verifying accuracy of meters that are directly connected to the owner's distribution system;

(f) to maintain information systems relating to the consumption of electricity by customers;

(g) to provide to a retailer or the owner's regulated rate provider sufficient, accurate and timely information about the retailer's or the regulated rate provider's customers, including metering information about the electricity consumed by those customers in order to enable the retailer or regulated rate provider to bill and to respond to inquiries and complaints from customers concerning billing for electricity services;

(h) to undertake financial settlement with the Independent System Operator for system access service;

(i) to act as a regulated rate provider to eligible customers who pay a regulated rate for electricity;

(j) to appoint or act as a default supplier, in accordance with the regulations, for eligible customers;

(k) to connect and disconnect customers and distributed generation in accordance with the owner's approved tariff and with principles established by the Commission regarding distributed generation;

(l) to carry out distribution tariff billing for electric distribution service under a distribution tariff;

(m) to respond to inquiries and complaints from customers respecting electric distribution service;

(n) if the electric distribution system is not an electric utility, to comply with rules respecting service standards made by the Commission under section 129(1) relating to

(i) billing and billing services to be provided to customers, and

(ii) the process, procedures and standards for transfer of data relating to distribution tariffs

as if the electric distribution system were an electric utility.

(2) Each owner of an electric distribution system must, in accordance with the regulations made by the Minister under section 108, maintain the records and provide the records to the persons specified in the regulations.

2003 cE-5.1 s105;2007 cA-37.2 s82(4);2011 c11 s3

Limitation on functions performed by electric distribution system owners

106 An owner of an electric distribution system shall not carry out any function required or permitted by this Act or the regulations to be carried out by a retailer except

(a) when a retailer has made arrangements under section 112 or 113,

(b) in respect of electricity services provided under a regulated rate tariff when the owner acts as a regulated rate provider, or

(c) if the owner is authorized under the regulations made by the Minister under section 108 to carry out that function.

107 Repealed 2007 cA-37.2 s82(4).

Regulations

108 The Minister may make regulations

(a) respecting the planning and expansion of electric distribution systems;

(b) adding to, clarifying, limiting or restricting any of the duties or functions of the owner of an electric distribution system and the manner in which the duties or functions are to be carried out;

(c) respecting the responsibilities of an owner of an electric distribution system

(i) to maintain records, the matters in respect of which a record must be maintained and the persons to whom the information must or may be provided;

(ii) to develop and offer non-discriminatory distribution tariffs;

(iii) to carry out billing;

(iv) to perform metering and to maintain information systems, including frequency of meter reading cycles, use of automated meter reading software and equipment, and access to meter data for retailers, the owner's regulated rate provider or customers;

(d) enabling persons other than owners of electric distribution systems to maintain information systems;

(e) respecting the matters that must be included in agreements or arrangements between owners of electric distribution systems and retailers, or the terms and conditions that must be included, or both, including:

(i) the performance security the owners may require retailers to provide;

(ii) the exchange of information required between owners and retailers;

(iii) matters related to billing and the maintenance of information systems;

(f) respecting the terms and conditions that must be included or form part of any agreement or arrangement between

(i) owners of electric distribution systems and customers, and

(ii) owners and retailers or regulated rate providers;

(g) establishing a code of conduct governing the relationship between

(i) an owner of an electric distribution system and its regulated rate provider,

(ii) an owner and its affiliated retailers, or

(iii) the owner's regulated rate provider and an affiliated retailer,

or any aspect of the activities of the parties in the relationship;

(h) respecting the agreements or arrangements between owners of electric distribution systems and eligible customers who pay a regulated rate;

(i) respecting regulated rate tariffs;

(j) exempting a regulated rate provider from ISO rules that require providing financial security in respect of electric energy acquired by the regulated rate provider to meet its obligations under the regulated rate tariff;

(k) replacing a regulated rate tariff with a default supply option;

(l) respecting the circumstances under which a person becomes a default supplier, the manner in which that occurs and the rights and obligations of default suppliers;

(m) respecting the rights and obligations of customers;

(n) respecting the accuracy of billing by regulated rate providers;

(o) defining “eligible customers”, “rate classification customers”, “affiliated electricity retailer”, “affiliated gas retailer” and “default supplier”.

2003 cE-5.1 s108;2007 cA-37.2 s82(4)

Part 8
Retail

Medicine Hat

109 Nothing in this Part applies

(a) to the electric distribution system owned by the City of Medicine Hat or a subsidiary of the City in the service area of the City, or

(b) to customers whose property is located in the service area of the City of Medicine Hat

unless the City or a subsidiary of the City

(c) has an affiliated retailer that provides retail electricity services outside the service area of the City, or

(d) provides electric distribution service outside the service area of the City.

2003 cE-5.1 s109;2007 cA-37.2 s82(4)

Customer’s right to purchase from retailer

110 Subject to this Act and the regulations, a customer has the right to obtain retail electricity services from a retailer.

Functions of retailers

111(1) Retailers must

(a) maintain records and accounts of their customers respecting the provision of retail electricity services;

(b) make a reasonable effort to collect amounts owing for retail electricity services before discontinuing retail electricity services to a customer;

(c) arrange for the exchange or purchase of electric energy on behalf of their customers;

(d) arrange for electric distribution service on behalf of their customers, including entering into agreements or arrangements with owners of electric distribution systems;

(e) respond to inquiries and complaints from their customers about retail electricity services.

(2) Retailers may

(a) provide retail electricity services to customers;

(b) exchange electric energy through the power pool on behalf of their customers.

2003 cE-5.1 s111;2007 cA-37.2 s82(4)

Billing

112(1) Only a retailer may bill a customer unless

(a) the retailer with the owner's consent authorizes the owner of an electric distribution system to charge customers directly under the owner's distribution tariff, or

(b) the regulations made by the Minister under section 115 provide otherwise.

(2) The authorization shall not restrict the manner in which the owner charges customers under its distribution tariff.

Authorization of another person

113(1) A retailer may make arrangements under which other persons perform any or all of the functions of the retailer under this Act or the regulations.

(2) No arrangement under subsection (1) affects or reduces the responsibility or liability of the retailer in relation to carrying out those functions.

Self retailer

114 A customer may carry out the functions of a retailer to obtain electricity for the customer's own use.

Regulations

115 The Minister may make regulations

(a) respecting the manner in which functions of retailers are to be carried out, including their rights and obligations and codes and standards governing their conduct;

(b) adding to, clarifying, limiting or restricting any of the functions of a retailer and the manner in which the functions are to be carried out;

(c) enabling persons other than owners of electric distribution systems to maintain information systems and respecting the compilation and dissemination of and access to information in those systems;

(d) respecting the responsibility of retailers to carry out billing or the accuracy of billing by retailers, or both;

(e) establishing a code of conduct governing the behaviour of a retailer providing a regulated rate on behalf of an owner of an electric distribution system;

(f) requiring retailers to be registered, with whom, and the information to be provided on registration and periodically after registration, registration renewal, the performance security to be provided by retailers, conditions on registration, the circumstances under which registration is suspended or cancelled and the effect of the suspension or cancellation of registration;

(g) adding to the definition of electricity services;

(h) respecting information that must be provided by retailers to persons specified in the regulations.

Part 9
Regulation by the Commission

Division 1
General Matters

Application of this Part

116(1) This Part applies

(a) to electric utilities operating in Alberta,

(b) to owners of electric utilities operating in Alberta,

(c) to electric utilities owned by the Crown, and

(d) to the ISO tariff.

(2) In this Part, "tariff application" means an application to the Commission under section 119(1) for approval of the tariff of an owner of an electric utility or the ISO tariff.

2003 cE-5.1 s116;2007 cA-37.2 s82(4)

Exemptions

117(1) The Commission may make rules

(a) exempting any facility or class of facilities from the definition of electric utility, or

(b) exempting from all or any provision of this Act and the regulations the electric energy produced from and consumed by an industrial system, and may impose terms and conditions on the exemption.

(2) If the Commission designates the whole or any part of an electric system as an industrial system under section 4(5) of the *Hydro and Electric Energy Act* and is considering making a rule under subsection (1)(b) in relation to that industrial system, the Commission may impose the condition that the owner of the industrial system be responsible for paying a just and reasonable share of the costs associated with the interconnected electric system.

2003 cE-5.1 s117;2007 cA-37.2 s82(4)

Duty to keep accounts and records

118(1) An owner of an electric utility must, with respect to the electric utility,

(a) maintain records and accounts in a manner that provides a reasonable understanding of the operation of the electric utility, including keeping track separately of the costs and expenses of

(i) transmission facilities, and

(ii) electric distribution systems,

(b) provide, when requested by the Commission, a detailed report of finances and operations relating to the electric utility in the form, containing the information and verified in the manner the Commission requires, and

(c) subject to any order of the Commission, maintain proper and adequate depreciation, amortization or depletion accounts using any basis or method the Commission directs.

(2) The Commission may make rules respecting the information required to be filed with the Commission and the person required to file it, including

(a) forecasts, and

(b) separate information in relation to transmission, distribution, exchange, purchase or sale of electric energy when one or more of those functions is undertaken by the same person.

(3) The Independent System Operator must, with respect to the transmission system, maintain the records and accounts and provide the reports required by the Commission.

2003 cE-5.1 s118;2007 cA-37.2 s82(4)

Division 2
Approval of Tariffs

Preparation of tariffs

119(1) Each owner of an electric utility must prepare a tariff in accordance with this Act and the regulations and apply to the Commission for approval of the tariff.

(2) An owner of an electric utility that makes a tariff application and that also owns isolated generating units must include the costs and expenses related to the isolated generating units in the application in accordance with the regulations.

(3) If the owner of an electric utility appoints a person to prepare a tariff on its behalf, that person must prepare the tariff and apply to the Commission for approval of the tariff.

(4) The Independent System Operator must prepare a tariff relating to the transmission system in accordance with Part 2 and apply to the Commission for approval of the tariff.

2003 cE-5.1 s119;2007 cA-37.2 s82(4)

Tariff contents

120(1) A tariff must describe how it may change over the period for which it is intended to have effect.

(2) A tariff may provide

(a) that it is in effect for a fixed period or an indefinite period;

(b) for maximum rates;

(c) for increases or decreases in the rates to correspond to

(i) increases or decreases in fuel costs, taxes or other costs and expenses,

(ii) price indices, rates of inflation or similar measurements, and

(iii) other related costs or expenses approved by the Commission;

(d) for incentives for efficiencies that result in cost savings or other benefits that can be shared in an equitable manner between the owner of the electric utility and customers.

2003 cE-5.1 s120;2007 cA-37.2 s82(4)

Matters the Commission must consider

121(1) On giving notice to interested parties, the Commission must consider each tariff application.

(2) When considering whether to approve a tariff application the Commission must ensure that

(a) the tariff is just and reasonable,

(b) the tariff is not unduly preferential, arbitrarily or unjustly discriminatory or inconsistent with or in contravention of this or any other enactment or any law, and

(c) if the regulations so require, the tariff incorporates the standard of liability imposed by the regulations made by the Lieutenant Governor in Council under section 94, or that the Commission has, in accordance with those regulations, considered and imposed a standard of legal liability that it considers appropriate.

(3) A tariff that provides incentives for efficiency is not unjust or unreasonable simply because it provides those incentives.

(4) The burden of proof to show that a tariff is just and reasonable is on the person seeking approval of the tariff.

2003 cE-5.1 s121;2007 cA-37.2 s82(4)

Costs and expenses recovered under a tariff

122(1) When considering a tariff application, the Commission must have regard for the principle that a tariff approved by it must provide the owner of an electric utility with a reasonable opportunity to recover

(a) the costs and expenses associated with capital related to the owner's investment in the electric utility, including

(i) depreciation,

(ii) interest paid on money borrowed for the purpose of the investment,

(iii) any return required to be paid to preferred shareholders of the electric utility relating to the investment,

(iv) a fair return on the equity of shareholders of the electric utility as it relates to the investment, and

(v) taxes associated with the investment,

if the costs and expenses are prudent and if, in the Commission's opinion, they provide an appropriate composition of debt and equity for the investment,

(b) other prudent costs and expenses associated with isolated generating units, transmission, exchange or distribution of electricity or associated with the Independent System Operator if, in the Commission's opinion, they are applicable to the electric utility,

(c) amounts that the owner is required to pay under this Act or the regulations,

(d) the costs and expenses applicable to the electric utility that arise out of obligations incurred before the coming into force of this section and that were approved by the Public Utilities Board, the Alberta Energy and Utilities Board or other utilities' regulatory authorities if, in the Commission's opinion, the costs and expenses continue to be reasonable and prudently incurred,

(e) its prudent costs and expenses of complying with the Commission rules respecting load settlement,

(f) its prudent costs and expenses respecting the management of legal liability,

(g) the costs and expenses associated with financial arrangements to manage financial risk associated with the pool price if the arrangements are, in the Commission's opinion, prudently made, and

(h) any other prudent costs and expenses that the Commission considers appropriate, including a fair allocation of the owner's costs and expenses that relate to any or all of the owner's electric utilities.

(2) When the Independent System Operator is the applicant for tariff approval, the Commission must have regard for the principle that a tariff approved by it must provide the Independent System Operator with a reasonable opportunity to recover all of the items referred to in subsection (1) that are applicable to the Independent System Operator.

(3) The Commission shall not decide that the ISO tariff fails to satisfy the requirements of section 121(2)(a) or (b) simply because the tariff provides for the flow through, including by the use of deferral accounts, real time pricing or other mechanisms, of some or all of the Independent System Operator's prudent costs and expenses of carrying out its duties, responsibilities and functions.

2003 cE-5.1 s122;2007 cA-37.2 s82(4)

Retrospective tariff

123 When considering whether to approve a tariff that is to have effect from a date preceding its consideration of the tariff application, the Commission may take into account evidence relating to revenues received and costs and expenses incurred by the applicant in the whole or part of the year in which the application is made.

2003 cE-5.1 s123;2007 cA-37.2 s82(4)

Powers of Commission

124(1) In respect of each tariff application, the Commission may, subject to section 135,

(a) approve a tariff or any part of it with or without changes, or

(b) refuse to approve a tariff or any part of it.

(2) An approval may be for an interim period specified by the Commission.

2003 cE-5.1 s124;2007 cA-37.2 s82(4)

Tariff must be approved

125 The owner of an electric utility and the Independent System Operator shall not put into effect a tariff that has not been approved by the Commission.

2003 cE-5.1 s125;2007 cA-37.2 s82(4)

126 Repealed 2007 cA-37.2 s82(4).

Obligations of owners of electric utilities and the Independent System Operator

127 The owners of an electric utility and, in respect of the ISO tariff, the Independent System Operator

(a) must provide and maintain service that is safe, adequate and proper,

(b) shall not withhold a service that the Commission has ordered it to provide, and

(c) shall not act in a manner that is unjust, unreasonable, unduly preferential, arbitrarily or unjustly discriminatory or inconsistent with or in contravention of this or any other enactment or any law.

2003 cE-5.1 s127;2007 cA-37.2 s82(4)

128 Repealed 2007 cA-37.2 s82(4).

Service quality standards

129(1) The Commission may make rules respecting service standards for each owner of an electric utility, including rules respecting the following:

(a) the standard of service to be maintained and how the standard is to be measured;

(b) service outages;

(c) upgrades required to maintain and improve electric distribution systems;

(d) the regular or periodic maintenance of electric utilities and repairs;

(e) customer care and call centre services to be provided for customers;

(f) the billing and billing services to be provided to customers;

(g) any matter related to public safety;

(h) the process, procedures and standards for transfer of data relating to distribution tariffs;

(i) the payment to the Commission of professional and other costs relating to the development, implementation and administration of the rules and by whom the costs are to be paid;

(j) roles, responsibilities and standards of accuracy with respect to metering and metering services.

(2) On application or on its own initiative, the Commission may investigate to determine whether the owner of an electric utility is complying with the rules respecting service standards.

(3) If the Commission is of the opinion that the owner of an electric utility has failed or is failing to comply with the rules respecting service quality standards, the Commission may by order do all or any of the following:

(a) direct the owner to take any action to improve services that the Commission considers just and reasonable;

(b) direct the owner to provide the customer with a credit, of an amount specified by the Commission, to compensate the customer for the owner's failure to comply with the rules respecting service quality standards;

(c) prohibit the owner from engaging in any activity or conduct that the Commission considers to be detrimental to customer service;

(d) impose an administrative penalty under section 63 of the *Alberta Utilities Commission Act*.

(4) Subsections (2) and (3) apply in respect of an owner of an electric distribution system that is required, by section 105(1)(n), to comply with rules made under subsection (1)(f) and (h).

2003 cE-5.1 s129;2007 cA-37.2 s82(4);2011 c11 s3

130 and **131** Repealed 2007 cA-37.2 s82(4).

Division 3
Negotiated Settlement of an Issue

Facilitated negotiation

132(1) The Commission must recognize or establish rules, practices and procedures that facilitate

(a) the negotiated settlement of matters arising under this Act or the regulations, and

(b) the resolution of complaints or disputes regarding matters arising under this Act or the regulations.

(2) Before recognizing or establishing rules, practices and procedures that affect the Independent System Operator, the Commission must consult with that corporation.

(3) The rules, practices and procedures recognized or established under this section apply whether or not an application relating to an issue has been made to the Commission.

2003 cE-5.1 s132;2007 cA-37.2 s82(4)

Powers of Commission

133 As part of the rules, practices and procedures for negotiated settlement of matters or the resolution of complaints or disputes, the Commission may

(a) provide for the appointment of mediators to assist parties in negotiating the settlement of an issue;

(b) provide for the appointment of employees of the Commission as mediators;

(c) provide for employees of the Commission to attend the settlement process;

(d) recognize or establish rules to ensure that the parties to an issue receive

(i) adequate notice of the settlement process and the matters in issue,

(ii) adequate disclosure of the positions of the parties and the basis for those positions, and

(iii) an appropriate opportunity to participate in the settlement process;

(e) recognize or establish rules governing the extent to which persons who are not parties or classes of persons who are not parties may participate in the settlement of an issue;

(f) provide that, before an issue may become the subject of a hearing before the Commission, the parties must attempt to negotiate a settlement of the issue in accordance with the Commission's rules, practices and procedures;

(g) determine whether any costs of negotiating the settlement of an issue are payable and, if so, by whom and to whom the costs are to be paid.

2003 cE-5.1 s133;2007 cA-37.2 s82(4);2011 c11 s3

Commission approval of a settlement

134(1) If a settlement has been negotiated of an issue that is within the jurisdiction of the Commission, the Commission may approve the settlement.

(2) Any issue dealt with in a settlement approved by the Commission is not subject to further consideration in the hearing of the matter to which the settlement relates.

(3) Subject to subsection (4), the Commission may require a party to provide to it any records relating to the settlement that it considers appropriate.

(4) The Commission shall not receive or consider any submission, position, evidence or information provided by a party on a without prejudice or confidential basis in the course of negotiating a settlement under this Part without the express consent of that party.

2003 cE-5.1 s134;2007 cA-37.2 s82(4)

Limit on Commission discretion

135 If the parties negotiate a settlement on the basis that the settlement is contingent on the Commission's accepting the entire settlement, the Commission must either approve the entire settlement or refuse it.

2003 cE-5.1 s135;2007 cA-37.2 s82(4);2011 c11 s3

Limit on mediators and facilitators

136 No person acting as a mediator or facilitator of a negotiated settlement or resolution of a complaint or dispute may participate in any proceedings of the Commission arising from or relating to the issue without the express consent of all the parties to the issue.

2003 cE-5.1 s136;2007 cA-37.2 s82(4)

Commission discretion

137(1) When considering a settlement that has been negotiated, the Commission

(a) may accept confidential records from the parties to an issue and, on acceptance, must maintain the confidentiality of the records, and

(b) may participate in or hold any discussions in private if the Commission considers it necessary and if all parties to the issue have notice of the discussions.

(2) The duty of the Commission to maintain the confidentiality of records provided to the Commission under subsection (1)(a) prevails despite the *Freedom of Information and Protection of Privacy Act* for a period of at least 10 years following the end of the year in which the negotiated settlement to which the documents or information relates has completely expired.

2003 cE-5.1 s137;2007 cA-37.2 s82(4)

Division 4
Municipally Owned Electric Utilities

Bylaw bringing utility under this Act

138(1) Any municipality that owns an electric distribution system may, by bylaw, provide that the system is an electric utility under this Act.

(2) The bylaw passed has no effect unless it is approved by the Lieutenant Governor in Council.

(3) If a bylaw has been passed and approved under this section or if the electric distribution system of a municipality is an electric utility under this Act, the municipality may, notwithstanding the bylaw or anything in this Act, impose amounts in respect of its electric distribution system that are in addition to the rates approved by the Commission if the bills submitted to customers

(a) clearly distinguish between the rates approved by the Commission and the additional amounts imposed by the municipality, and

(b) identify the additional amounts imposed by the municipality as a surcharge or tax.

2003 cE-5.1 s138;2007 cA-37.2 s82(4)

Division 5
Rights Granted by a Municipality

Grant of right to distribute electric energy

139(1) A right to distribute electricity granted by a municipality

(a) to an owner of an electric distribution system has no effect unless the grant is approved by the Commission;

(b) to a subsidiary of the municipality does not require Commission approval.

(2) The Commission may approve the grant of a right to distribute electricity when, after hearing the interested parties or with the consent of the interested parties, the Commission determines that the grant is necessary and proper for the public convenience and to properly serve the public interest.

(3) The Commission may, in giving its approval, impose any conditions as to construction, equipment, maintenance, service or operation that the public convenience and the public interest reasonably require.

(4) A municipality shall not grant to another municipality or to a corporation controlled by another municipality the right to distribute electricity to customers in the granting municipality unless the grant

(a) is approved by the Commission, and

(b) is authorized by regulations under subsection (5).

(5) On the recommendation of the Minister that a grant described in subsection (4) is, in the Minister's opinion, in the public interest, the Lieutenant Governor in Council may make regulations authorizing the grant and respecting any conditions that apply to the grant.

(6) For the purpose of subsection (4), a corporation is controlled by a municipality if the test set out in section 1(2) of the *Municipal Government Act* is met.

2003 cE-5.1 s139;2007 cA-37.2 s82(4)

Limits on approval of grants

140 The Commission shall not approve a grant under section 139 unless

(a) it is a term of the grant that the grant does not prevent the Crown from exercising that right,

(b) the person seeking the grant has satisfied the Commission that the proposed scheme for the distribution of electricity is reasonable and sufficient, having regard to the general circumstances, and

(c) the Commission is satisfied that the grant is to the general benefit of the area directly or indirectly affected by it.

2003 cE-5.1 s140;2007 cA-37.2 s82(4)

Grant to person outside Alberta

141(1) No municipality may grant to a person that is not subject to the legislative authority of Alberta a right to operate, manage or control any plant, works, equipment, systems or services for the transmission, distribution or provision of electricity, either directly or indirectly, in all or part of the municipality.

(2) Subsection (1) does not apply if the grant contains a provision, approved by the Commission, that the person to whom the right is granted agrees to submit its business and operations to the control and supervision of the Commission in the same manner and to the same extent as if that person were an owner of an electric utility.

(3) A right granted by a municipality contrary to this section is void.

2003 cE-5.1 s141;2007 cA-37.2 s82(4)

Part 10
General Matters

Regulations

142(1) The Lieutenant Governor in Council may make regulations

(a) defining any word or expression that is used but not defined in this Act or in regulations made by the Minister;

(b) dealing with any difficulty or impossibility resulting from the coming into force of this Act or the transition to this Act from the *Electric Utilities Act*, RSA 2000 cE-5;

(c) respecting the treatment of the rights and obligations of rural electrification associations under contracts that were in existence on April 30, 1998 and that are made with owners of electric utilities, where the rights and obligations are necessary or advisable to carry out the purposes of this Act;

(d) respecting the authority of the Minister to extend dates or lengthen periods expressly specified in this Act, whether the date or the period specified in the Act has or has not expired;

(e) respecting costs relating to reclamation of a hydro facility and who is to pay those costs in the event that the Government of Alberta requires that a hydro facility be reclaimed;

(f) authorizing a supervisory authority named in the regulations to impose administrative penalties of not more than $100 000 a day and to impose other sanctions and orders for contravention of or to enforce compliance with regulations made under this Act, and conferring authority on the Court of Queen's Bench to enforce the penalties, orders or other sanctions;

(g) respecting the conversion or transition to this Act of anything from the *Electric Utilities Act*, RSA 2000 cE-5;

(h) requiring the City of Medicine Hat or a subsidiary of the City to provide information or statements of compliance to the chair of the Commission, including certifying or confirming the accuracy of information or compliance statements provided, respecting sections 2(1)(a), 37(2)(a), 95, 100, 109, 153(1) or other sections of this Act which apply to the City or a subsidiary of the City or which exempt the City or a subsidiary of the City from this Act;

(i) respecting regulatory oversight of the regulated rate tariff for municipalities and rural electrification associations that do not have affiliated retailers;

(j) requiring the owner of an electric distribution system to apply to the Commission for approval of a regulated rate tariff despite section 103(3) and (4);

(k) requiring rates for the ISO's tariff as set out in section 30(3)(a) to apply to market participants in addition to those market participants described in section 30(3)(a);

(l) respecting any aspect of the interconnected electric system, including, without limitation, regulations

(i) respecting the use of the interconnected electric system for the import and export of electricity,

(ii) respecting the implementation of principles and requirements related to the import and export of electricity,

(iii) setting out the principles and criteria that the Commission must or may have regard for when considering approval of

(A) a needs identification document described in section 34,

(B) an expansion or enhancement of the transmission system, or

(C) a tariff of the ISO, an owner of a transmission facility or an owner of an electric distribution system,

(iv) respecting costs and any other matters relating to the planning, development, construction and operation of a safe, reliable and economic interconnected electric system,

(v) respecting directions that the Independent System Operator may give to owners of transmission facilities or other market participants or persons relating to

(A) critical transmission infrastructure and other transmission facilities,

(B) the planning, development, construction and operation of a safe, reliable and economic interconnected electric system, or

(C) ensuring an adequate supply of electricity on a short-term basis or during abnormal conditions,

(v.1) respecting the planning, development, construction and operation of transmission facilities, including

(A) critical transmission infrastructure,

(B) interties, and

(C) transmission facilities to serve areas of renewable energy,

and who is responsible for paying the costs related to the facilities referred to in paragraphs (A), (B) and (C),

(v.2) respecting plans under section 33, including

(A) which plans the Independent System Operator must consult on,

(B) the matters that must be included in plans,

(C) whom the Independent System Operator must consult with, and

(D) the extent or nature of the consultation,

(v.3) respecting the determination of who may apply for the construction or operation, or both, of transmission facilities, including

(A) who may make the determination, and

(B) determining who may apply, based on

(I) a competitive process, or

(II) some other method or process,

(v.4) respecting the principles and criteria that the Commission must have regard to when determining the specific location or detailed route of critical transmission infrastructure or other transmission facilities,

(v.5) respecting

(A) the establishment of a committee comprising the Independent System Operator, representatives of customers, and other persons determined by the regulation to provide records to customers in relation to the construction of transmission facilities, including records relating to the costs, scope and construction schedules of proposed transmission facilities, and

(B) the records of the Independent System Operator, transmission facility owners and persons directed under section 35 or 41.3 that must be provided to the committee for the purpose of paragraph (A),

and

(vi) respecting the combining of an application for an approval under the *Hydro and Electric Energy Act* with an application for approval of a needs identification document described in section 34;

(l.1) respecting reliability standards for or in relation to transmission facilities, electric distribution systems or generating units or the owners or users of those facilities, systems or units.

(m) repealed 2007 cA-37.2 s82(4).

(2) The Lieutenant Governor in Council may make regulations

(a) respecting any matter that the Minister considers

(i) is not provided for or is insufficiently provided for in this Act, or

(ii) is necessary or advisable in connection with the implementation of this Act;

(b) exempting any person or class of persons from any provision of this Act or the regulations and prescribing conditions or restrictions on the exemption;

(c) conferring or imposing on any person or class of persons engaged in the supply, generation, transmission, distribution, trade, exchange, purchase or sale of electricity, electric energy, electricity services or ancillary services any power, duty, responsibility or function necessary to carry out the purposes of this Act;

(d) adding to, clarifying, limiting or restricting any power, duty, responsibility or function conferred or imposed on any person or class of persons under this Act or regulating how they are to be exercised, despite any other provision of this Act or the regulations;

(e) allocating, determining, fixing or prescribing anything required by this Act to be allocated, determined, fixed or prescribed, including the manner of allocation, determination, fixing or prescription, if not specified in this Act;

(f) respecting any matters, in addition to or in place of those specified in this Act, to be considered by the Commission in making an order under this Act;

(g) suspending the operation of any provision of this Act or making any provision of this Act inapplicable if, in the Minister’s opinion, that is necessary or advisable to carry out the purposes of this Act.

(3) A regulation made under subsection (2) is repealed on the earliest of

(a) the coming into force of an amendment to this Act that adds the matter to this Act,

(b) the coming into force of a regulation that repeals the regulation made under subsection (2), and

(c) 5 years after the regulation comes into force.

(4) The repeal of a regulation under subsection (2) does not affect anything done, incurred or acquired under the authority of the regulation.

2003 cE-5.1 s142;2007 cA-37.2 s82(4);2009 c44 s2

Ministerial regulations

142.1 The Minister may make regulations respecting the definition of roles and responsibilities and establishment of rules for procedures and equipment, including testing and audit procedures and equipment and service standards, with respect to metering.

2007 cA-37.2 s82(4)

Extent of regulations

143 Any regulation made by the Minister or the Lieutenant Governor in Council under this Act may

(a) be specific or general in its application and include conditions, restrictions and limitations;

(b) apply to all or any part of Alberta;

(c) impose or confer on any person named in the regulations any power, duty, responsibility or function in respect of the regulation;

(d) adopt or declare to be in force any code or standard, with or without modifications, specified or described in the regulation.

144 and **145** Repealed 2007 cA-37.2 s82(4)

Regulations Act – non-application

146 The *Regulations Act* does not apply to

(a) ISO bylaws or the ISO rules;

(b) Balancing Pool bylaws.

Payment in lieu of income tax

147(1) In this section, "municipal entity" means

(a) each municipality that

(i) owns a retailer,

(ii) holds a power purchase arrangement, or

(iii) holds an agreement or arrangement derived from a power purchase arrangement that includes the right to exchange electric energy and ancillary services;

(b) each retailer that is a subsidiary of a municipality;

(c) each holder of a power purchase arrangement that is a subsidiary of a municipality;

(d) each holder of an agreement or arrangement derived from a power purchase arrangement that includes the right to exchange electric energy and ancillary services that is a subsidiary of a municipality.

(2) If the regulations under subsection (8) so provide, "municipal entity" also includes:

(a) each municipality or subsidiary of a municipality that owns an electric distribution system;

(b) each municipality or subsidiary of a municipality that provides a regulated rate tariff;

(c) each municipality or subsidiary of a municipality that owns a transmission facility.

(3) If a municipal entity is exempt as a result of subsection 149(1) of the *Income Tax Act* (Canada) from the payment of tax under that Act or the *Alberta Corporate Tax Act*, it must, in accordance with the regulations, pay to the Balancing Pool in respect of each taxation year an amount equal to the amount of tax that it would be liable to pay under

(a) the *Income Tax Act* (Canada), and

(b) the *Alberta Corporate Tax Act*,

if it were not exempt.

(4) Revenue received by a municipal entity

(a) from an electric distribution system owned by it,

(b) from a customer who chooses to purchase electricity under a regulated rate tariff, or

(c) from a transmission facility owned by it,

shall not be considered income received by a municipal entity for the purposes of subsection (3) unless required by the regulations made under subsection (8).

(5) Subsection (3) does not apply to the City of Medicine Hat or to a subsidiary of the City.

(6) The City of Medicine Hat and each subsidiary of the City must pay to the Balancing Pool an amount calculated in accordance with the regulations made under subsection (8).

(7) If the City of Medicine Hat or a subsidiary of the City is subject to payment of tax under the *Income Tax Act* (Canada) or the *Alberta Corporate Tax Act*, subsection (6) does not apply to the City or its subsidiary.

(8) The Lieutenant Governor in Council may make regulations for the purposes of this section, including regulations

(a) respecting the calculation of the amount to be paid to the Balancing Pool under subsection (3);

(b) respecting the interval for payment of the amount to be paid to the Balancing Pool;

(c) making this section applicable to any of the municipal entities described in subsection (2) and the revenue described in subsection (4);

(d) respecting the calculation of amounts to be paid to the Balancing Pool by the City of Medicine Hat or a subsidiary of the City;

(e) making any provisions of the *Income Tax Act* (Canada) and the *Alberta Corporate Tax Act* and regulations under either or both enactments, with or without modifications, applicable to the person named in the regulations.

(9) A regulation made under subsection (8) may provide for the retroactive application of the regulation, but not to a date earlier than January 1 of the year in which the regulation is made.

Approved professional costs

148(1) The Minister may approve the professional and other costs relating to the development and implementation of this Act, amendments to this Act and regulations under this Act, including costs relating to advancing the purposes of this Act and regulations.

(2) Costs approved by the Minister under subsection (1) must be paid by the Balancing Pool.

Advisory committee

149(1) The Minister may establish a committee under section 7 of the *Government Organization Act*.

(2) The Minister must appoint as members of the committee such corporations, municipalities, organizations or individuals as may, in the opinion of the Minister, be necessary or desirable to ensure that the membership of the committee is representative of persons having a material interest in the Alberta electric industry.

(3) Each corporation, municipality and organization that is a member of the committee must nominate an individual to serve as its representative on the committee and may nominate different individuals for that purpose from time to time.

Offences

150(1) A person who fails to comply with this Act or the regulations is guilty of an offence.

(2) A person who advises, solicits, persuades, instructs, directs or orders a person

(a) to do an act or thing prohibited by this Act or the regulations, or

(b) to omit to do an act or thing required to be done by this Act or the regulations

is guilty of an offence.

(3) A person who is guilty of an offence under this section is liable to a fine not exceeding $3 000 000 for each day or part of a day on which the offence occurs or continues.

(4) Where a person is convicted of an offence under this section and the court is satisfied that as a result of the commission of the offence the person derived an economic benefit directly or indirectly, the court may order the person to pay, in addition to a fine under subsection (3), a fine in an amount equal to the court's estimate of the amount of the economic benefit.

(5) A prosecution may not be commenced after

(a) 3 years from the date that the facts that constitute the alleged offence become known to the Commission, or

(b) 6 years from the date of the occurrence of the alleged offence,

whichever occurs first.

2003 cE-5.1 s150;2007 cA-37.2 s82(4)

Part 11 Transitional Provisions, Consequential Amendments and Coming into Force

Division 1 Transitional Provisions

Transition of Power Pool Council and Transmission Administrator

151(1) In this section,

(a) "assets and liabilities" means all rights, property, assets, obligations and liabilities whatsoever, including without limitation contingent assets and liabilities and all agreements and arrangements;

(b) "balancing pool" means the balancing pool established by the *Balancing Pool Regulation* (AR 169/99);

(c) "balancing pool administrator" has the meaning given to it by the *Balancing Pool Regulation* (AR 169/99);

(d) "decisions" means an order, interim order, decision, fine or sanction made or imposed before the coming into force of this section by the Power Pool Council or the balancing pool administrator under the previous Act or the regulations under that Act;

(e) "Power Pool Council" means the Power Pool Council that existed under the previous Act before the coming into force of this section;

(f) "previous Act" means the *Electric Utilities Act*, RSA 2000 cE-5.

(2) Within 15 days of the coming into force of this section, the Power Pool Council must determine:

(a) the allocation among the Independent System Operator, the Market Surveillance Administrator and the Balancing Pool of the assets and liabilities of the Power Pool Council, and

(b) the designation among the Independent System Operator, the Market Surveillance Administrator and the Balancing Pool of its decisions and of the decisions of the balancing pool administrator.

(3) In making the determination, the Power Pool Council must have regard for the following:

(a) the assets and liabilities of the Power Pool Council that relate to a duty, responsibility or power of the Independent System Operator are to be the assets and liabilities of the Independent System Operator;

(b) the assets and liabilities of the Power Pool Council that relate to the mandate or a responsibility or power of the Market Surveillance Administrator are to be the assets and liabilities of the Market Surveillance Administrator;

(c) the assets and liabilities of the Power Pool Council that relate to a duty, responsibility or power of the balancing pool are to be the assets and liabilities of the Balancing Pool;

(d) the decisions that relate to a duty, responsibility or power of the Independent System Operator are to be orders of the Independent System Operator;

(e) the decisions that relate to the mandate or a responsibility or power of the Market Surveillance Administrator are to be orders of a tribunal;

(f) the decisions that relate to the balancing pool or to a duty, responsibility or power of the balancing pool administrator are to be decisions of the Balancing Pool.

(4) On the later of

(a) the coming into force of Parts 2, 3 and 4, and

(b) the determination being made by the Power Pool Council under subsection (2),

as the case requires,

(c) the assets and liabilities of the Power Pool Council are the assets and liabilities of the Independent System Operator, the Market Surveillance Administrator and the Balancing Pool, respectively, in accordance with the determination made by the Power Pool Council, and

(d) the decisions are continued as orders of the Independent System Operator, as tribunal orders or as decisions of the Balancing Pool, as the case may be, in accordance with the determination made by the Power Pool Council.

(5) Despite the repeal of the previous Act, the Power Pool Council is continued for the purpose of making the determination required by subsection (2).

(6) A determination made by the Power Pool Council under subsection (2) is final, and shall not be questioned, reviewed or restrained by any proceeding in the nature of an application for judicial review or otherwise in any court.

(7) Any agreement, arrangement or other instrument in force on the day this section comes into force to which the Power Pool Council is a party does not cease to have effect as a result of the coming into force of this Act.

(8) The Independent System Operator, the Market Surveillance Administrator or the Balancing Pool, as the case may be, in accordance with the determination made by the Power Pool Council under subsection (2),

(a) is the successor in interest of the Power Pool Council in an agreement, arrangement or other instrument referred to in subsection (7), and

(b) is deemed to be a party to an agreement, arrangement or other instrument referred to in subsection (7) in substitution for the Power Pool Council.

(9) The rules of the power pool made by the Power Pool Council under section 9 of the previous Act and rules made under the Power Pool Council under any regulations made under that Act are deemed to be ISO rules until the earlier of

(a) the repeal of those rules by the Independent System Operator under this Act, and

(b) 60 days after the coming into force of this section.

Transmission Administrator assets and liabilities disposition

152(1) In this section,

(a) "assets and liabilities" means all rights, property, assets, obligations and liabilities whatsoever, including without limitation contingent assets and liabilities and all agreements and arrangements;

(b) "previous Act" means the *Electric Utilities Act*, RSA 2000 cE-5;

(c) "Transmission Administrator" means Transmission Administrator of Alberta Ltd.

(2) On the coming into force of this section,

(a) the assets and liabilities of the Transmission Administrator are the assets and liabilities of the Independent System Operator;

(b) the tariff of the Transmission Administrator approved under the previous Act is the ISO tariff until a replacement for that tariff is approved under this Act.

(3) Any agreement, arrangement or other instrument in force on the day this section comes into force to which the Transmission Administrator is a party does not cease to have effect as a result of the coming into force of this Act.

(4) The Independent System Operator

(a) is the successor in interest of the Transmission Administrator in an agreement, arrangement or other instrument referred to in subsection (3), and

(b) is deemed to be a party to an agreement, arrangement or other instrument referred to in subsection (3), in substitution for the Transmission Administrator.

Rates for transmission facilities owned by municipalities

153(1) This section applies only to a municipality or a subsidiary of a municipality, other than the City of Edmonton or the City of Medicine Hat, that owns transmission facilities.

(2) Despite the repeal of the *Electric Utilities Act*, RSA 2000 cE-5, and despite section 37 of this Act, if the Minister has under section 30 of the *Electric Utilities Act*, RSA 2000 cE-5, approved rates to be paid to the owner of a transmission facility, the rates approved by the Minister apply until the earlier of

(a) the date specified by the Minister in the order or other instrument approving the rates as the date those rates cease to apply or expire, and

(b) December 31, 2005.

(3) The rates described in subsection (2) are deemed to satisfy the requirements of Part 9 during the period of time that the rates are in effect.

Continuation of regulations if needed

154(1) The Minister may make regulations continuing, with or without modifications, a regulation made under the *Electric Utilities Act*, SA 1995 cE-5.5 or the *Electric Utilities Act*, RSA 2000 cE-5, as a regulation made under this Act,

(a) whether or not there exists legislative authority for that regulation under this Act, and

(b) whether made by the Lieutenant Governor in Council or the Minister.

(2) A regulation made under subsection (1) expires 2 years after it is made unless earlier repealed.

(3) A regulation made under subsection (1) operates in addition to the provisions of the *Interpretation Act* that govern the continuation of regulations where an enactment is repealed and replaced by a new enactment.

Continuation of approvals, orders, etc.

155 Any approval, order, direction or other determination and any instrument relating to

(a) an electric utility,

(b) the owner of an electric utility, or

(c) the Transmission Administrator

made under the *Public Utilities Board Act*, the *Hydro and Electric Energy Act*, the *Electric Utilities Act*, SA 1995 cE-5.5, or the *Electric Utilities Act*, RSA 2000 cE-5, before the coming into force of this section does not cease to have effect as a result of the coming into force of this Act.

Deferral account and other definitions

156 In sections 157 to 159,

(a) "deferral account" means

(i) in respect of ATCO Electric Ltd., a deferral account established for 2000 referred to in clauses 28, 29, 30 and 31 of the Alberta Power Limited 1999/2000 Phase I Negotiated Settlement dated April 21, 1999 and approved by the Alberta Energy and Utilities Board in Decision U99046 dated May 10, 1999,

(ii) in respect of UtiliCorp Networks Canada (Alberta) Ltd., a deferral account established for 2000 referred to in the Summary of Board Directions numbered 58, 59 and 60 in Part 1 – General, of Board Decision U99099 dated November 25, 1999, and

(iii) in respect of a municipal owner of an electric distribution system, a reconciliation account for 2000 established for the same purpose as that for which a deferral account referred to in subclause (i) or (ii) is established;

(b) "municipal owner of an electric distribution system" means

(i) Enmax Power Corporation,

(ii) EPCOR Distribution Inc.,

(iii) the City of Lethbridge, and

(iv) the City of Red Deer;

(c) "regulatory authority" means

(i) in respect of a municipality or a subsidiary of a municipality that owns an electric distribution system, the council of the municipality,

(ii) in respect of a rural electrification association, the board of directors of the rural electrification association, or

(iii) in respect of any other owner of an electric distribution system, the Alberta Energy and Utilities Board.

2003 cE-5.1 s156;2007 cA-37.2 s82(4)

Approval of collection

157 A regulatory authority may approve the collection by the owner of an electric distribution system of amounts in respect of its deferral accounts during the period January 1, 2002 to December 31, 2004.

Balancing Pool obligations

158 The Balancing Pool must pay any amount payable by the Balancing Pool pursuant to a transaction, agreement or obligation relating to the deferral accounts, reconciliation accounts and the accounts established for similar purposes relating to a regulated rate tariff that the balancing pool administrator entered into, including

(a) transactions and agreements as principal, obligor, indemnitor, guarantor, surety or assignee of deferral and reconciliation accounts, and

(b) obligations to make payments in respect of amounts at any time comprising deferral accounts, reconciliation accounts and accounts established for similar purposes, including the collection, financing or purchase by any person of those amounts.

Existing deferral accounts

159 The deferral, reconciliation and other accounts referred to in section 158 must relate to the period of time before January 1, 2002.

Application

160 Sections 157 and 158 do not apply after December 31, 2004.

ISO tariff in 2003

161 When considering whether to approve the tariff of the Transmission Administrator that is to have effect for 2003, the Alberta Energy and Utilities Board must include in that tariff the ability of the Transmission Administrator to recover an amount equal to

(a) the aggregate of

(i) the price paid by the Power Pool Council or its subsidiary to acquire the shares of ESBI Alberta Ltd.,

(ii) all reasonable transition costs incurred by the Power Pool Council or its subsidiary related to acquisition of the shares of ESBI Alberta Ltd., and

(iii) any additional income or corporate taxes payable by the Transmission Administrator as a result of including the price referred to in subclause (i) and the costs referred to in subclause (ii) in the Transmission Administrator's tariff,

less

(b) any management fees collected by the Transmission Administrator after the date on which the Power Pool Council or its subsidiary acquires the shares of ESBI Alberta Ltd.

2003 cE-5.1 s161;2007 cA-37.2 s82(4)

Recovery of costs incurred

162 The Independent System Operator must recover the price referred to in section 161(a)(i) and the costs referred to in section 161(a)(ii) after the payment of the additional income or corporate taxes referred to in section 161(a)(iii).

ISO's tariff

163 The ISO's tariff is not unjust or unreasonable simply because it includes the amount referred to in section 161.

Division 2
Consequential Amendments and Coming into Force

164 to **166** *(These sections amend other Acts; the amendments have been incorporated into those Acts.)*

Repeal of regulations

167 The following regulations are repealed:

(a) *Deficiency Correction Regulation, 2002* (AR 53/2002);

(b) *Direct Sales Regulation* (AR 167/2001);

(c) *Liability Protection Regulation* (AR 237/2001);

(d) *Load Curtailment and Reliability Deficiency Correction Regulation* (AR 114/2001);

(e) *Power Pool Council Deficiency Correction Regulation* (AR 173/2002);

(f) *Municipal Long Term Electricity Agreement Regulation* (AR 73/2002);

(g) *Time Extension Regulation* (AR 162/98);

(h) *Time Extension Regulation* (AR 243/99);

(i) *Time Extension Order* (AR 198/2000);

(j) *Transmission Administrator Tariff Deficiency Correction Regulation* (AR 240/2002).

Repeals

168(1) The *Electric Utilities Act*, RSA 2000 cE-5, is repealed.

(2) Sections 156 to 163 of this Act are repealed on Proclamation.

Coming into force

169 This Act comes into force on Proclamation.

(NOTE: Proclaimed in force June 1, 2003.)

Schedule

Critical Transmission Infrastructure

Each of the critical transmission infrastructure described in this Schedule includes all associated facilities required to interconnect a transmission facility described in this Schedule to the interconnected electric system.

The following transmission facilities are designated as critical transmission infrastructure:

1(1) Two high voltage direct current transmission facilities between the Edmonton and Calgary regions, with a minimum capacity of 2000 megawatts each, generally described as follows:

(a) one facility with a northern terminal in the vicinity of the existing Keephills - Genesee generating units and the southern terminal at or in the vicinity of the existing Langdon 102S substation, and

(b) one facility, located east of the facility described in clause (a) and geographically separated from that facility for the purposes of ensuring reliability of the transmission system, with a northern terminal at or in the vicinity of a new substation to be built in the Gibbons - Redwater region and a southern terminal

(i) at or in the vicinity of the existing West Brooks 28S substation, or

(ii) at or in the vicinity of a new substation to be located in the Raymond - Bow Island region.

(2) The terminals referred to in subsection (1)(a) and (b) shall have an initial capacity of at least 1000 megawatts each and be expandable to a minimum capacity of 2000 megawatts each in accordance with section 41.4(1) of this Act.

2 One double circuit 500 kV alternating current transmission facility connecting to the 500 kV transmission system on the south side of the City of Edmonton and to a new substation to be built in the Gibbons - Redwater region.

3 A new 240 kV substation to be built in the southeast area of the City of Calgary.

4 Two single circuit 500 kV alternating current transmission facilities from the Edmonton region to the Fort McMurray region, generally described as follows:

(a) a facility from a new substation to be built in the Thickwood Hills area, approximately 25 km west of the Fort McMurray Urban Service Area, to a substation at or in the vicinity of the existing Brintnell 876S substation;

(b) a facility at or in the vicinity of the existing Brintnell 876S substation, to a substation in the vicinity of the existing Keephills - Genesee generating units;

(c) a facility, located east of the facilities described in clauses (a) and (b) and geographically separated from those facilities for the purposes of ensuring reliability of the transmission system, from a new substation to be built in the Gibbons - Redwater region to a new substation to be built in the Thickwood Hills area, approximately 25 km west of the Fort McMurray Urban Service Area.

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AUC Rule 002

Rule 002

Service Quality and Reliability Performance Monitoring and Reporting for Owners of Electric Distribution Systems and for Gas Distributors

This rule as amended was approved by the Alberta Utilities Commission on March 23, 2010 and is effective on July 1, 2010.

Contents

1 General provisions

1.1 Rule application

The quality of services provided by owners of electric distribution systems that are electric utilities and by gas distributors is measured under Rule 002. The quality of services provided to customers by a default supply provider or a regulated rate provider, as those terms are defined in the *Gas Utilities Act* and the *Electric Utilities Act* respectively, is measured under Rule 003: *Service Quality and Reliability Performance Monitoring and Reporting for Regulated Rate and Default Supply Providers*, even if those services are to the same sites or customers as those provided under this rule.

1.2 Definitions

In this rule,

(a) “business day” has the meaning ascribed to the term “business day” as defined in the ISO Rules and as shown on the Stakeholder Calendar posted on the ISO’s website;

(b) “Commission” means the Alberta Utilities Commission;

(c) “electric distribution system” has the meaning ascribed to the term in the *Electric Utilities Act*;

(d) “electric utility” has the meaning ascribed to the term in the *Electric Utilities Act*;

(e) “gas distributor” has meaning ascribed to the term in the *Gas Utilities Act*;

(f) “ISO” means the Independent System Operator as defined in the *Electric Utilities Act*;

(g) “MDM” means Meter Data Manager as defined in Rule 021: *Settlement System Code Rules*;

(h) “owner” means an owner of an electric distribution system that is an electric utility or a gas distributor;

(i) “Rule 002” means this Rule 002: *Service Quality and Reliability Performance Monitoring and Reporting for Owners of Electric Distribution Systems and for Gas Distributors*;

(j) “Rule 002 annual report” means the reporting of service quality and reliability performance, as detailed in this Rule 002, prepared and submitted annually in accordance with Section 2.2; and

(k) “Rule 002 quarterly report” means the reporting of service quality and reliability performance metrics, as detailed in this Rule 002, prepared and submitted quarterly in accordance with Section 2.1.

2 Measurement and reporting protocol

For the purpose of collecting data and reporting on performance in each of the categories established in sections 3 or 4, the owner must comply with the information filing requirements set out in this Section 2.

The owner must advise the Commission of any change to the owner's internal reporting methods that may impact its ability to comply with this Rule 002 and provide an explanation for the change prior to implementing such a change. Any data related to this rule that reflect significantly altered measurement procedures or internal data acquisition methods shall be subject to Commission review and approval.

2.1 Rule 002 quarterly report

(1) Reporting periods shall be calendar quarters, with Rule 002 quarterly reports submitted to the Commission by the last day of the month following the end of each quarter: April 30 is the deadline for the first quarter report, July 31 is the deadline for the second quarter report, October 31 for the third quarter report and January 31 for the fourth quarter report.

(2) Unless specifically identified as being reported only in the Rule 002 annual report, metrics identified as required in this Rule 002 are required to be reported in the Rule 002 quarterly reports.

2.2 Rule 002 annual report

(1) The Rule 002 annual report shall be submitted to the Commission no later than the last day of February following the end of the calendar year.

(2) The Rule 002 annual report shall consist of an accumulation of the quantitative data reported in the Rule 002 quarterly reports, additional annual metrics and qualitative information required for explaining trends, corrective action plans and reasons for variances from standards.

(3) Whenever the minimum performance standards set out in sections 3 or 4, as may be applicable, are not met by an owner, the reasons for failing to meet the standard and the corrective actions taken must be explained in the Rule 002 annual report. If the Commission is satisfied that exceptional circumstances existed, the Commission may waive any applicable performance standard in the event of a failure to meet that standard. The burden shall be on the owner to demonstrate that its level of preparedness and response was reasonable in light of the circumstances surrounding the failure to meet the standard.

2.3 Annual meeting

(1) After submission of the Rule 002 annual report to the Commission, the owner and the Commission will meet at least once annually to discuss service quality issues, trends in service quality data reported by the owner, including any corrective action plans proposed by the owner to remedy failing performance standards, issues raised by customer complaints filed with the Commission, and other policy

issues relating to customer service. Meetings may occur more frequently at the Commission's discretion.

2.4 Templates for Rule 002 quarterly reports and Rule 002 annual reports

(1) The templates (and instructions for completion) for reporting performance results to the Commission are available on the Rule 002 website at www.auc.ab.ca.

(2) In order to allow the Rule 002 annual report to accumulate the data provided in the Rule 002 quarterly reports, the owner must enter data for second, third and fourth quarter Rule 002 quarterly reports in the same copy of the template they used for the previous quarter(s).

(3) Quantitative data and graphical depiction of the data are the outputs of the templates.

(4) Qualitative explanations as required by this rule for the Rule 002 annual report are considered part of the Rule 002 annual report but are not included as part of the templates. A letter or Microsoft Word document containing the required qualitative information for the Rule 002 annual report must accompany the quantitative data and graphical depiction of the data that are outputs from the templates.

2.5 Backups and missing data

(1) The owner must retain any documentation that is required as backup for the Rule 002 quarterly reports and the Rule 002 annual reports for not less than 24 months after the results are reported. The owner must provide these reports to the Commission upon request.

(2) The owner must report missing data or other events that could reasonably affect the quality of the data immediately after becoming aware of the missing data or events.

3 Performance categories and standards for owners of electric distribution systems

This Section establishes the performance categories and, where applicable, the standards to be met by owners of electric distribution systems that are electric utilities and outlines the information required by the Commission for it to accomplish its regulatory function with respect to service quality standards as provided for under this rule. Unless specifically identified as being only reported in the Rule 002 annual report, metrics identified as required in this Rule 002 are required to be reported in the Rule 002 quarterly reports and the Rule 002 annual reports.

3.1 Billing and meter reading performance measures

The reporting of both monthly and exception metrics by the owner in Rule 002 quarterly reports and Rule 002 annual reports will provide the Commission with information about the owner's progress towards the goal of having every site billed every month based on accurate, actual meter readings. In addition, the metrics provide visibility to the Commission of the owner's performance in relation to meter reading and billing rules found in Rule 021: *Settlement System Code Rules* (Rule 021) and Rule 004*: Alberta Tariff Billing Code* (Rule 004).

3.1.1 Monthly billing and meter reading performance

For this metric, the owner must identify the number of sites it owns that have been assigned a meter reading and billing cycle as of month end (total sites). The total sites should match the number of sites in the month-end version of the owner's Site Cycle Catalogue file (SCF file). (See Rule 004).

Of the total sites, the owner shall report the number billed sometime in the month (sites billed) and the number not billed (sites not billed). For both sites billed and sites not billed, the owner shall provide a breakdown of how many there are of each of the following types:

(a) Unmetered sites;
(b) Interval metered sites;
(c) De-energized sites;
(d) Cumulative metered energized sites with actual meter readings obtained by the MDM and provided to parties in accordance with Section 11.3.4 of Rule 021 (as opposed to customer reads or actual reads not provided to parties in accordance with that Section); and
(e) Cumulative metered energized sites without actual meter readings provided to parties in accordance with Section 11.3.4 of Rule 021.

3.1.2 Cumulative meters not read within six months

The performance standard set out in Section 11.3 of Rule 021 provides that the MDM must obtain and provide to parties in accordance with Section 11.3.4 of Rule 021 at least one meter reading from 100 per cent of cumulative meters once every six months at a minimum. This Rule 002 applies the same standard to the owner.

The owner shall identify and report all cases where the above standard was not met, grouping them by reason that a read was not obtained and by the number of months since a read was obtained and provided to parties in accordance with Section 11.3.4 of Rule 021 for those meters.

3.1.3 Identified meter errors

The owner shall report meter errors of the following types that are identified in a given month:

(a) Meter multiplier errors;
(b) Crossed meters; and
(c) Theft.

For all errors identified during a quarter, the owner shall report the number of sites where they identified such errors and the number of years the errors existed before they were identified.

3.1.4 Monthly tariff billing performance

The owner shall report its monthly performance in relation to Metric #1, Currency of Tariff Bill File Content, of Rule 004, which states that the calculation of the following formula should result in a number that is 95 per cent per month or greater:

> Formula: Number of sites within original tariff bill files with a site production reason code of "2020 – Regular Billing Cycle," where the tariff bill file date created minus the current bill period end date for each site is less than or equal to eight business days, divided by the total number of sites with that same site production reason code in original tariff bill files.

The owner shall report its monthly performance in relation to Metric #2, File Completeness, of the Rule 004, which states that the calculation of the following formula should result in a number that is 98 per cent per month or greater:

> Formula: Number of sites assigned to billing cycles and transmitted in original tariff bill files on their scheduled tariff bill file publish date with a site production reason code of "2020 – Regular Billing Cycle," divided by the total number of sites expected to bill for those billing cycles.

The owner shall also report monthly the numbers of Tariff Bill Rejections (TBRs) and Tariff Bill File Disputes (TBDs), by reason code (see Rule 004), sent to the owner each month by retailers. Along with the numbers of TBDs and TBRs, the owner shall report the numbers of those transactions it rejected or invalidated.

3.2 Work completion performance measures

Owners must track and report work completion performance in relation to the following work, after requests have been sent to them by retailers:

(a) Energizing sites;
(b) De-energizing sites; and
(c) Performing off-cycle meter reads.

For energize request (ENR) and energize completion (ENC) transactions, owners must track and report the following:

(a) Monthly average number of days from when the owner creates an order in its system for the energization to when the site becomes energized;
(b) End-to-end time involved (on average for the month) from receipt of request to perform the work (from the retailer) to the response back to the retailer that the work has been successfully completed. The starting and ending times for this measurement are the time stamps given to the transactions (ENRs and ENCs) in the owner's system; and
(c) Total number of completed energizations per month.

For de-energize request (DER) and de-energize completion (DEC) transactions, owners must track and report the following:

(a) Monthly average number of days from when the owner creates an order in its system for the de-energization to when the site becomes de-energized;
(b) End-to-end time involved (on average for the month) from receipt of request to perform the work (from the retailer) to the response back to the retailer that the work has been successfully completed. The starting and ending times for this measurement are the time stamps given to the transactions (DERs and DECs) in the owner’s system; and
(c) Total number of completed de-energizations per month.

For off-cycle meter read request (ROR) and off-cycle meter read completion (ROC) transactions, owners must track and report the following:

(a) Percentage of completed off-cycle meter reads where the time from the request to perform the work from the retailer to the response back to the retailer that the work has been successfully completed is five business days or less. The starting and ending times for this measurement are the time stamps given to the transactions (RORs and ROCs) in the owner’s system; and
(b) Total number of completed off-cycle meter reads per month.

Customer-impacting issues may arise when there is a lag in the period of time between when an owner completes work and when that completed work is reflected in its systems. For example, if a customer’s power has been disconnected because of a retailer request, and later on the same day, the retailer requests that the power be turned back on, if the owner’s system still shows the power as being on even after the disconnect, the owner may or may not process the request to re-energize the site, which may cause significant problems for the customer involved.

As a means of measuring whether or not system lags are causing work completion problems, owners shall report the number of times each month that an energization request is failed by the owner, with a failure reason indicating that it was failed because the site is already energized. While retailers may mistakenly request energization for sites that are already energized, frequent occurrences of energization failures with reason codes of “Already Energized” may be an indication of problems caused by lags within the owner’s systems.

3.3 Worker safety performance measures

The performance indices defined by the Canadian Electricity Association (CEA) must be adopted to measure worker safety performance. Owners must report the numbers required by the CEA formulas annually.

3.3.1 All injury/illness frequency rate (Rule 002 annual report only)

Owners shall report the following metrics (as defined by the CEA):

(a) Lost Time Injuries;
(b) Medical Treatment Injuries;

(c) Fatalities; and
(d) Exposure Hours.

3.3.2 Motor vehicle incident frequency (Rule 002 annual report only)

Owners shall report the annual number of recordable motor vehicle incidents (as defined by the CEA) and the annual number of actual kilometers driven by corporate fleet vehicles.

3.4 Reliability performance measures

Owners shall report certain indices defined by the CEA to measure electric distribution system performance and reliability. Two versions of those metrics must be reported: (1) with major events included and (2) with major events excluded. When determining which major events to exclude, the owner shall continue to use the same methodology they used in previous years to allow comparison with historic data. In the absence of historic data with major events excluded, the owner must consult with the Commission before choosing a methodology.

3.4.1 System average interruption frequency index (SAIFI) (Rule 002 annual report only)

This measure pertains to distribution-related interruptions and is defined as the average number of times that a customer experiences an interruption. SAIFI must be reported both with and without major events and calculated according to the CEA formulas. Annual numbers must be provided (to two decimal places) as part of the Rule 002 annual report.

3.4.2 Customer average interruption duration index (CAIDI) (Rule 002 annual report only)

This measure also pertains to distribution-related interruptions but measures the average length of time required to restore service to a customer affected by an interruption. CAIDI must be reported both with and without major events and calculated according to the CEA formulas. Annual numbers must be provided (to two decimal places) as part of the Rule 002 annual report.

3.4.3 System average interruption duration index (SAIDI) (Rule 002 annual report only)

This measure also pertains to distribution-related interruptions and is defined as the amount of time in total the average customer experiences interruptions. SAIDI must be reported both with and without major events and calculated according to the CEA formulas. Annual numbers must be provided (to two decimal places) as part of the Rule 002 annual report.

3.4.4 SAIDI of worst-performing circuits on the system (Rule 002 annual report only)

For each calendar year, the owner must identify the top three per cent of worst-performing circuits on its system based on the owner's formalized evaluation process for determining worst-performing circuits and report them in the Rule 002 annual report. The owner must identify the factors underlying the poor performance of these circuits and describe, in the Rule 002 annual report, the actions that are being considered or have been implemented to improve the reliability of these circuits.

All circuits that were once identified according to this standard must be monitored each year over a five-year period to determine the effectiveness of the improvement measures and to identify further measures that may be required.

In the Rule 002 annual report, the owner must report the SAIDI metric for each of the worst-performing circuits. For each circuit that was once a worst-performing circuit, the owner must report its SAIDI metric (as a former worst-performing circuit) and report the last calendar year that the circuit appeared in the worst-performing circuit list.

3.5 Post-final adjustment mechanism (PFAM) adjustments processed

The owner shall report the number of PFAM adjustments it processed, as set out in Section 5 of Rule 021, by month, by classification of the PFAM and by the type of error that resulted in the PFAM.

When reporting the PFAM adjustments processed, the owner shall report to the Commission the number of sites and the number of kilowatt hours over-or under-allocated to retailers as a result of the errors triggering the PFAMs. If an error caused the consumption used by a site to be charged to the wrong retailer, the site shall be counted only once in the site count, but the consumption will be counted both in the over-allocated and the under-allocated kilowatt hours, because one retailer was allocated too much consumption and the other retailer allocated too little.

3.6 Customer satisfaction measures

3.6.1 Percentage of customer satisfaction following customer-initiated contact with the owner (Rule 002 annual report only)

For this measure, the owner must report the level of customer satisfaction using the results from its internal customer satisfaction survey process or using the results from the survey process of an independent third-party agency. Whether the owner conducts surveys on an ongoing basis throughout the year or it conducts the survey on an annual basis, the owner shall report the results as part of the Rule 002 annual report. The owner must use the sampling method described in Appendix A. The survey instrument must be a telephone questionnaire using survey questions listed in Appendix A, as well as any additional questions that the owner may add.

The minimum performance standard for this customer satisfaction measure is 75 per cent of customers must agree with the statements about the owner (see Appendix A).

3.6.2 Overall customer satisfaction measures (Rule 002 annual report only)

The owner must measure overall customer satisfaction once annually. Using an independent third-party agent or its own internal survey process, the owner must survey a sample of the owner’s customers to assess general customer satisfaction in the following areas:

(a) customer service; and
(b) distribution service.

The owner (or third-party agent) must use the sampling methodology described in Appendix B. The survey instrument must be a telephone questionnaire using survey questions also listed in Appendix B, as well as any additional questions that the owner may add.

The minimum performance standard is 75 per cent of customers must agree with the statements about the owner (see Appendix B).

3.6.3 Complaint response

The owner shall track and report customer-specific issues brought forward to the owner by the Commission (complaints), whether written or verbal, and report the number of days required to close each complaint. Once a complaint has been initiated, it cannot be reported closed until all of the following conditions have been met:

(1) The owner has provided to the Commission any information requested by the Commission regarding the complaint;

(2) The Commission has not indicated that the complaint must remain open until the Commission is able to contact the customer; and

(3) If corrections to the customer's account are required, the owner has either informed the Commission of when the customer can expect to see those corrections or the owner has provided details regarding steps that will be taken to correct the account.

The owner must close complaints according to the following standards:

(1) 80 per cent of the complaints directed to the owner in any given month must be closed within 14 calendar days of receipt of the complaint; and

(2) 100 per cent of the complaints directed to the owner in any given month must be closed within 30 calendar days of receipt of the complaint.

4 Performance categories and standards for gas distributors

This section establishes the performance categories and, where applicable, the standards to be met by gas distributors. This section also outlines the information required by the Commission for it to accomplish its regulatory function with respect to service quality standards as provided for under this rule. Unless specifically identified as being only reported in the Rule 002 annual report, metrics identified as required in this Rule 002 are required to be reported in the Rule 002 quarterly reports and the Rule 002 annual report.

4.1 Billing and meter reading performance measures

The reporting of both monthly and exception metrics by the owner in Rule 002 quarterly reports and Rule 002 annual reports will provide the Commission with information about the owner's progress towards the goal of having every site bill every month based on accurate, actual meter readings. In addition, the metrics provide visibility to the Commission of the owner's performance in relation to the requirements of Rule 004.

4.1.1 Cumulative meters not read within four months and one year

The owner shall report the number of sites that have not had their meter read within four months and within twelve months.

For those sites that have not had their meters read within twelve months, the owner must report the reason why and what course of action the owner will take to get the meters read and ensure that the problem does not occur again in the future.

4.1.2 Monthly tariff billing performance

The owner shall report its monthly performance in relation to Metric #1, Currency of Tariff Bill File Content, of Rule 004, which states that calculation of the following formula should result in a number that is 95 per cent per month or greater:

> Formula: Number of sites within original tariff bill files with a site production reason code of "2020 – Regular Billing Cycle," where the tariff bill file date created minus the current bill period end date for each site is less than or equal to eight business days, divided by the total number of sites with that same site production reason code in original tariff bill files.

The owner shall report its monthly performance in relation to Metric #2, File Completeness, of Rule 004, which states that calculation of the following formula should result in a number that is 98 per cent per month or greater:

> Formula: Number of sites assigned to billing cycles and transmitted in original tariff bill files on its scheduled tariff bill file publish date with a site production reason code of "2020 – Regular Billing Cycle," divided by the total number of sites expected to bill for those billing cycles.

The owner shall also report monthly the numbers of tariff bill rejections (TBRs) and tariff bill file disputes (TBDs), by reason code (see Rule 004), sent to the owner each month by retailers. Along with the numbers of TBDs and TBRs, the owner shall report the numbers of those transactions it rejected or invalidated.

4.2 Worker safety performance measures

4.2.1 All injury/illness frequency rate (Rule 002 annual report only)

Owners shall report the following metrics in accordance with the formulas and definitions historically used by the owner:

(a) Lost Time Injuries;
(b) Medical Treatment Injuries;

(c) Fatalities; and
(d) Total Hours Worked.

4.2.2 Motor vehicle incident frequency (Rule 002 annual report only)

Owners shall report the annual number of recordable motor vehicle incidents and the annual number of actual kilometers driven by corporate fleet vehicles (as per the definitions used by the Canadian Gas Association).

4.3 Customer satisfaction measures

4.3.1 Percentage of customer satisfaction following customer-initiated contact with the owner (Rule 002 annual report only)

For this measure, the owner must report the level of customer satisfaction using the results from its internal customer satisfaction survey process or using the results from the survey process of an independent third-party agency. Whether the owner conducts surveys on an ongoing basis throughout the year or it conducts the survey on an annual basis, the owner shall report the results as part of the Rule 002 annual report. The owner must use the sampling methodology described in Appendix A. The survey instrument must be a telephone questionnaire using survey questions listed in Appendix A, as well as any additional questions that the owner may add.

The minimum performance standard for this customer satisfaction measure is 75 per cent of customers must agree with the statements about the owner (see Appendix A).

4.3.2 Overall customer satisfaction measures (Rule 002 annual report only)

The owner must measure overall customer satisfaction once annually. Using an independent third-party agent or its own internal survey process, the owner must survey a sample of the owner's customers to assess general customer satisfaction in the following areas:

(a) customer service; and
(b) distribution service.

The owner (or third-party agent) must use the sampling methodology described in Appendix B. The survey instrument must be a telephone questionnaire using survey questions also listed in Appendix B, as well as any additional questions that the owner may add.

The minimum performance standard is 75 per cent of customers must agree with the statements about the owner (see Appendix B).

4.3.3 Complaint response

The owner shall track and report customer-specific issues brought forward to the owner by the Commission (complaints), whether written or verbal, and report the number of days required to close each complaint. Once a complaint has been initiated, it cannot be reported closed until all of the following conditions have been met:

(1) The owner has provided to the Commission any information requested by the Commission regarding the complaint;

(2) The Commission has not indicated that the complaint must remain open until the Commission is able to contact the customer; and

(3) If corrections to the customer's account are required, the owner has either identified to the Commission when the customer can expect to see those corrections or the owner has provided details regarding steps that will be taken to correct the account.

The owner must close complaints according to the following standards:

(1) 80 per cent of the complaints directed to the owner in any given month must be closed within 14 calendar days of receipt of the complaint; and

(2) 100 per cent of the complaints directed to the owner in any given month must be closed within 30 calendar days of receipt of the complaint.

Appendix A – Customer-initiated contact satisfaction survey

Customer satisfaction survey following customer-initiated contact with the owner

The focus of this customer-initiated contact satisfaction survey is on residential, farm, irrigation and small commercial customers who have recently contacted their owner. The survey is limited to customers who contacted the owner through the company's call centre, the use of email or the Internet via the owner's website.

Owners can choose their own frequency for administering the customer-initiated contact satisfaction survey, but the responses shall be amalgamated throughout the year and reported in the Rule 002 annual report.

The customer-initiated contact satisfaction survey includes a study of customer contacts made with the owner within, at most, 30 days after the owner/customer interaction has taken place. The owner selects a random sample from its database of all customer-initiated contacts. The study must achieve a minimum sample of 400 completed questionnaires each year. The recommended sample size of 400 is designed to have a plus or minus five per cent sampling error at the 95 per cent confidence level.

The owner must attempt to reach the person who contacted the owner. Customers who have been surveyed within the past 12 months shall be excluded from the survey, as shall customers who earlier indicated that they do not wish to be surveyed. Finally, through a survey question, any customer who has been employed by the owner within the past two years or whose household contains someone who has been employed by the owner within the past two years shall not be included in the survey.

The survey must include the following questions:

> In light of your recent experience with [*Insert name of owner*], please indicate whether you agree or disagree with each of the following statements:
>
> a. [*Insert name of owner*] makes it easy for customers to reach them.
>
> b. [*Insert name of owner*]'s employees are helpful.
>
> c. [*Insert name of owner*]'s employees are knowledgeable.
>
> d. [*Insert name of owner*]'s employees are courteous.
>
> e. [*Insert name of owner*]'s employees provide satisfactory service.

Appendix B – Overall satisfaction survey

Overall customer satisfaction survey

The focus of this overall satisfaction survey is on residential, farm, irrigation and small commercial customers who are customers of the owner at the time of the survey. The survey must be administered annually and the results reported in the Rule 002 annual report.

Respondents are chosen randomly from the customer base of the owner. The study must achieve a minimum sample of 400 completed questionnaires each year. The recommended sample size of 400 is designed to have a plus or minus five per cent sampling error at the 95 per cent confidence level.

Customers who have been surveyed within the past 12 months by the owner shall be excluded from the survey, as shall customers who indicated previously to the owner that they do not wish to be surveyed. Finally, through a survey question, any customer who has been employed by the owner within the past two years or whose household contains someone who has been employed by the owner within the past two years shall not be included in the survey.

The survey must include the following questions:

> For each of the following statements about [*Insert name of owner*], please indicate whether you agree or disagree with the statement:
>
> a. [*Insert name of owner*] provides reliable [*Insert electricity or gas*].
>
> b. [*Insert name of owner*] provides good service to their customers.
>
> c. [*Insert name of owner*] has a good reputation in the community.

AUC Rate Regulation Initiative

Decision **2012-237**

AUC
Alberta Utilities Commission

Rate Regulation Initiative

Distribution Performance-Based Regulation

September 12, 2012

The Alberta Utilities Commission
Decision 2012-237: Rate Regulation Initiative
Distribution Performance-Based Regulation
Application No. 1606029
Proceeding ID No. 566

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1 Introduction and background

1. On February 26, 2010, the Alberta Utilities Commission (AUC or Commission) began a rate regulation initiative to reform utility rate regulation in Alberta. The first stage of the rate regulation initiative is to implement a form of performance-based regulation (PBR) for electric and natural gas distribution companies in place of the existing cost of service regulatory system, usually referred to as rate base rate-of-return regulation. The second stage of the rate regulation initiative will consist of generic reviews of legal and economic issues related to utility regulation for the purpose of making the regulatory system more consistent among companies, more predictable over time and more efficient.

2. In its February 26, 2010 letter,[1] the Commission indicated that the first stage of the rate regulation initiative would apply only to the electricity and natural gas services of Alberta distribution companies under the Commission's jurisdiction. It would not apply to the electricity and natural gas services of transmission companies or to retail electricity or natural gas sales. However, if a company provided both distribution and transmission services, the company was given the option to apply to include its transmission services in its PBR proposal.

3. The procedural steps for this stage of the rate regulation initiative are set out in Appendix 3 to this decision. The division of the Commission presiding over this proceeding was Mr. Willie Grieve (chair), Mr. Mark Kolesar and Dr. Moin Yahya.

4. This decision sets out the Commission's determinations about the form of performance-based regulation that will be employed beginning in 2013 for Alberta electric and natural gas distribution companies.

1.1 The current regulatory framework

5. The utility companies to which this decision applies (the companies) are three electric distribution companies, ATCO Electric Ltd. (ATCO Electric or AE), FortisAlberta Inc. (Fortis or FAI) and EPCOR Distribution & Transmission Inc. (EPCOR or EDTI) and two gas distribution companies, ATCO Gas and Pipelines Ltd. (ATCO Gas or AG) and AltaGas Utilities Inc. (AltaGas or AUI). The distribution and transmission service rates charged by these companies are currently regulated under a rate base rate-of-return form of cost of service regulation.

6. The Commission also regulates the distribution and transmission rates of ENMAX Power Corporation (ENMAX or EPC). In 2009, the Commission approved a formula-based ratemaking

[1] Exhibit 1.01, AUC letter of February 26, 2010.

or FBR plan (also known as a PBR plan) for ENMAX's distribution and transmission services.[2] Prior to that, ENMAX was also regulated under a rate base rate-of-return framework.

7. Under the current rate base rate-of-return regulatory framework, rates are established through a two-phase process. In the first phase, the total amount of money required by the company to provide its regulated services in a year is determined. This is referred to as the revenue requirement, and it is made up of the total annual operating, maintenance and administrative expenses of the company plus the company's capital-related costs (depreciation, debt, and return on equity). The company's debt and equity are used to finance the company's assets (wires, pipes, etc.), which are referred to as its rate base. The cost of debt is the interest that the company pays on its bonds. The cost of equity is determined by the regulator and is referred to as the approved rate of return on equity (ROE). The return on equity actually earned is sometimes referred to as the utility company's profit since all other expenses and costs (operating, maintenance, administration and debt costs) are recovered without any profit margin built into them.

8. In the second phase of a rate application, monthly, hourly or other rates to be paid by individual customers for use of the distribution system are established by determining how much of the revenue requirement should be recovered from each customer class (residential, commercial, etc.) and on what billing unit basis (monthly charge, per kilowatt hour or gigajoule, etc.). Rates are established by dividing the revenue requirement for each customer class by the billing units.

9. In Alberta, all of these determinations are made on a forecast basis, generally for two years. So, for example, a company could file a rate application for the two years 2011 and 2012. A forecast revenue requirement would be provided by the company for each of the two years, called test years. The Commission is required to test the application for reasonableness and allow only reasonable forecast expenses, including capital-related costs, to be included in the revenue requirement and rates for the two test years. These forecasts are based on the companies' plans and expectations over the two test years. When new rates are implemented for the two years, the company begins to collect them and may or may not carry out the plans it put before the Commission in its forecasts. At the end of the two years, the company may apply for rates for the next two test years.

10. If the company is able to provide service for less than it had forecast during the previous two years, or if billing units (the number of customers, electricity or natural gas use, etc.) are greater than were forecasted, the company is permitted to keep the extra revenue as extra profit in those years. However, the forecast revenue requirement and rates for the next two years are to take into account the actual results from the previous two years. In this way, customers receive the benefit of the company's improved productivity (lower costs and higher billing units) from the previous period in the rates determined for the next two years. If the company then improves its productivity in these next two years, those benefits will again be passed on to customers in the next period, etc. Of course, the actual results for the immediate prior year are not available to assist in assessing the forecasts for the two test years of a new test period. This means that any efficiency gains in the prior year may not be fully incorporated into those forecasts.

[2] Decision 2009-035: ENMAX Power Corporation, 2007-2016 Formula Based Ratemaking, Application No. 1550487, Proceeding ID No. 12, March 25, 2009.

11. While this regulatory model is relatively straightforward in its conception, it produces some incentives and disincentives that are widely recognized.[3] Generally, under cost of service regulation, since the company earns a profit on the equity in its rate base, there is an incentive to choose spending money on capital assets, on which a return can be earned, over spending on maintenance, for example, on which a return is not earned. In addition, there is no incentive to minimize the costs of capital assets. The more that is spent and included in the company's rate base, the more return that can be earned. This means that the regulator must make some sort of after-the-fact assessment of whether the company spent too much money on capital assets and, if so, must disallow recovery of the amount by which actual costs exceeded a prudent amount. In addition, there is little incentive for the company to invest in long term cost reduction initiatives because any cost reductions achieved would be passed on to customers automatically in subsequent rate proceedings. The use of forecasted test years in Alberta was adopted partly in response to these incentives. However, while there are incentives to reduce expenses in the test years so as to beat the forecast and thereby increase profits, this only works for investments in efficiency that can be recovered in a year or two. In addition, this framework also creates an incentive for the companies to provide cost forecasts (both operating and maintenance (O&M), and capital) that are higher than what the company expects to be able to achieve or to provide conservative forecasts of the number customers and other billing units that are lower than what the company expects, thus increasing profits above the approved return.

12. In addition to the issues raised by the basic regulatory model, the framework has been made more complicated by the restructuring of the industries. In both the electricity and natural gas industries, companies that were once vertically integrated monopolies engaged in electricity generation, distribution, transmission and retailing, or in natural gas production, distribution, transportation and retailing, are now structurally separated. The production of electricity and natural gas and the retailing of electricity and natural gas are now open to competition. The costs for the distribution and transmission services must be separated from the costs of production and retailing and separate rate bases established. Issues of cost allocations among different regulated entities or among regulated and unregulated affiliates in the same corporate structure emerge and must be monitored. These issues include allocations of rate base, charges from one division to another, prices charged by affiliates providing services in competitive markets that also provide those services to the regulated affiliate, among others. In the current regulatory framework, each of these issues must be monitored and assessed in every regulatory application, and a number of new regulatory tools have been developed to deal with these costs and allocations both within and outside of the normal rate review process. As a consequence, the industry restructuring has added to the need for rate riders (items on the bill to recover costs that change from time to

[3] See Brown, Carpenter and Pfeifenberger regarding capital expenditure gaming (Exhibit 34.01, slide 3); Dr. Carpenter regarding incentive to bias its rate base allowance upward, (Transcript Volume 7, pages 1194 and 1195); Dr. Cronin that regulated firms are overcapitalized (Exhibit 299.02, page 124); Dr. K. Gordon, ATCO Gas witness in an earlier proceeding regarding over-forecasting, (Exhibit 357.06 citing Application No. 1400690, 2005-2007 Rate Application, Transcript Volume 5, pages 838-846); Ms. Frayer and Dr. Weisman, regarding cost-of-service's significant regulatory burden (Fortis application, Exhibit 100.02, Appendix 2, page 5, lines 20-23 and Exhibit 103.03, Dr. Weisman evidence, page 9, paragraph 20); Dr. Weisman's evidence that cost-of-service regulation "is essentially a cost-plus contract" (Exhibit 103.03 page 23 paragraph 57); Calgary evidence that a "regulated firm may use its information advantage strategically in the regulatory process to increase its profits … to the disadvantage of ratepayers." Exhibit 298.02, page 15, paragraph 34; The United States Department of Justice that "cost-of-service regulation may do little to promote, and may actually inhibit the achievement of, technical, allocative, or dynamic efficiency" as quoted by the UCA in Exhibit 299.02, page 119.

time[4]), flow-through mechanisms and deferral accounts. At last count the Commission was administering approximately 100 deferral accounts, riders and pass-through mechanisms for the distribution and transmission companies under cost of service regulation.

13. One result of the basic regulatory model and the industry restructuring that has been imposed on top of it has been both a tremendous increase in the detailed information filed by the regulated companies and an increase in the number of ongoing proceedings for deferral accounts and related matters. For example, in a recent revenue requirement application filed by EPCOR amounted to approximately 4,200 pages including all schedules and appendices.[5] The process that followed produced another 8,000 pages of information requests and responses as well as additional evidence and written questions and responses. In addition, from that proceeding, one of the issues was spun-off to be considered in a separate proceeding. As another example, there is a 10-year ongoing series of proceedings to benchmark and, through that, to establish a method to review and approve charges to the ATCO utilities by their affiliate ATCO I-Tek Inc.[6] As a further complication, a number of issues have been litigated differently by different companies and decided differently by different board[7] or Commission panels.

1.2 Performance-based regulation

14. In its February 26, 2010 letter, the Commission stated that the rate regulation initiative:

> ... proceeds from the assumption that rate-base rate of return regulation offers few incentives to improve efficiency, and produces incentives for regulated companies to maximize costs and inefficiently allocate resources. In addition, rate-base rate of return regulation is increasingly cumbersome in an environment where some companies offer both regulated and unregulated services and where operations that were formerly integrated have been separated into operating companies, some of which require their own rate and revenue requirement proceedings. These changes in the structure of the industry, occasioned by the introduction of competition in the retail and generation/production segments of the electricity and natural gas industries, have resulted in additional negative economic incentives for companies regulated under rate-base rate of return regulation. These conditions complicate the task for regulators who must critically analyze in detail management judgments and decisions that, in competitive markets and under other forms of regulation, are made in response to market signals and economic incentives. The role of the regulator in this environment is limited to second guessing. Traditional rate-base rate of return regulation provides few opportunities to create meaningful positive economic incentives which would benefit both the companies and the customers. The Commission is seeking a better way to carry out its mandate so that the legitimate expectations of the regulated utilities and of customers are respected.[8]

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4 Examples of rate riders include but are not limited to: ENMAX's Quarterly Transmission Access Charge, FortisAlberta's Quarterly Transmission Access Rider, ATCO Electric's Rider S Quarterly System Access Services Adjustment and EPCOR'S Rider K Transmission Charge Deferral Account True-up Rider.

5 EPCOR Distribution & Transmission Inc., 2010-2011 Phase I Distribution Tariff, 2010-2011 Transmission Facility Owner Tariff, Application No. 1605759, Proceeding ID No. 437.

6 Decision 2010-102: ATCO Utilities (ATCO Gas, ATCO Pipelines and ATCO Electric Ltd.), 2003-2007 Benchmarking and ATCO I-Tek Placeholders True-Up, Application No. 1562012, Proceeding ID No. 32, March 8, 2010; Decision 2011-228: ATCO Utilities (ATCO Gas, ATCO Pipelines and ATCO Electric Ltd.), 2008-2009 Evergreen Application, Application No. 1577426, Proceeding ID No. 77, May 26, 2011; ATCO Utilities, 2010 Evergreen Proceeding for Provision of Information Technology and Customer Care and Billing Services Post 2009, Application No. 1605338, Proceeding ID No. 240.

7 The Alberta Energy and Utilities Board (board or EUB), is a predecessor to the Alberta Utilities Commission.

8 Exhibit 1.01, AUC letter of February 26, 2010, pages 1-2.

15. In stating its intention to move to a performance-based regulation framework for the distribution companies, the Commission also stated the following objectives for PBR:

> The first is to develop a regulatory framework that creates incentives for the regulated companies to improve their efficiency while ensuring that the gains from those improved efficiencies are shared with customers. The second purpose is to improve the efficiency of the regulatory framework and allow the Commission to focus more of its attention on both prices and quality of service important to customers.[9]

16. A basic PBR plan begins with rates established through a cost of service proceeding such as a rate base rate-of-return proceeding. Those rates are then adjusted in subsequent years by a rate of inflation (I) relevant to the prices of inputs the companies use less an offset (X) to reflect the productivity improvements the companies can be expected to achieve during the PBR plan period. Thus, adjusting rates by I-X, rather than in cost of service proceedings, breaks the link between a utility's own costs and its revenues during the PBR term. In much the same way as prices in competitive industries are established in a competitive market, prices adjusted by I-X reflect industry-wide conditions that would produce industry price changes in a competitive market. Each company's actual performance under PBR will depend on how its own performance compares to the industry's inflation and productivity measures.

17. Establishing prices in this way during the term of a PBR plan creates stronger incentives for the companies to improve their efficiency through cost reductions and other actions because they are able to retain the increased profits generated by those cost reductions longer than they would under cost of service regulation, especially with rates under cost of service regulation that are re-set every two years. At the same time, under a PBR regulatory framework, customers automatically share in the expected efficiency gains because they are built into rates through the X factor regardless of the actual performance of the companies. In addition, the X factor in a PBR plan is often increased by a stretch factor so as to capture efficiency gains that should be immediately realizable as the regulatory system changes from cost of service to PBR.

18. But an I-X mechanism alone is not sufficient. In competitive markets, other factors that affect only the industry in question, such as an increase in taxes, would be passed through to customers by that industry in its competitive prices. PBR plans typically include a Z factor to deal with such significant events outside the companies' control that are specific to the industry and would not be reflected through the inflation factor (I). The Z factor can also be used to increase or decrease the companies' prices to reflect cost changes caused by unique company-specific events (such as floods or ice storms) outside the company's control and that are not reflected in the inflation factor.

19. In some cases, these types of costs may be predictable, although the amounts of these costs may not be. In those cases, other mechanisms may be established to allow for automatic adjustments to rates to pass those costs through to customers. For example, in the ENMAX FBR plan established in Decision 2009-035, the Commission made provision for the flow-through of transmission system charges imposed on the distribution company by the Alberta Electric System Operator (AESO).[10] Other similar types of charges beyond the control of the companies

9 Exhibit 1.01, AUC letter of February 26, 2010, page 1.
10 Decision 2009-035, pages 52-53. For further discussion on the AESO's role see Section 7.4.2.1.1.

may also be included in a PBR plan as a Y factor to be passed through to customers. The companies' proposals in this proceeding included a number of these types of factors.

20. In the ENMAX FBR plan,[11] the Commission also established a G factor to deal with capital additions to ENMAX's transmission system. In this proceeding, each of the companies proposed specific provisions for some types of capital investments to be handled outside the I-X mechanism. In this decision those types of capital adjustments are referred to as K factors.

21. All of these types of cost-based adjustments (whether Z, Y or K) are carefully defined and limited in their scope because they are inconsistent with the objectives of PBR in that they have the effect of lessening the efficiency incentives that are central to a PBR plan.

22. PBR plans are typically established for a defined term such as five years. At the end of the term, rates are often re-established in a cost of service proceeding, and another PBR term begins based on those rates. Other approaches may also be used at the end of the PBR term, such as simply continuing the plan or making some changes to the parameters and continuing based on existing rates. However, it is likely that a cost of service review will occur eventually.[12] In either case, the values of I and X, for example, and the other parameters of the plan are reviewed and may be changed. The fact that eventually rates will be re-established based on cost of service lessens the efficiency incentives under PBR as the time for the cost of service review approaches. Generally, the longer the PBR term, the greater are the incentives for the company to look for and invest in new productivity-enhancing business practices.

23. Whereas an I-X mechanism creates efficiency incentives similar to those in competitive markets, it does not create incentives to maintain quality of service. In a competitive market, poor service quality will cause customers to switch companies, but poor service quality will not result in a loss of customers for a monopoly. The fact of monopoly supply of an essential public service has required regulators to monitor and regulate service quality, regardless of the form of regulation. The Commission has recognized from the outset of its rate regulation initiative that the creation of greater efficiency incentives through adoption of a PBR plan also creates concerns that the resulting cost cutting might lead to reductions in quality of service. It is for this reason that the adoption of PBR typically coincides with the development and adoption by regulators of stronger quality of service regulatory measures.

24. It is the Commission's expectation that the adoption of a PBR plan will make the regulatory system more efficient over time as the Commission, interveners and companies become more familiar with it. At the same time the Commission expects that, under PBR, customers will experience lower rates than they would have had if the current rate base rate-of-return framework had continued unchanged.

25. During the first PBR term, the Commission will also conduct generic proceedings to deal with a number of utility regulatory issues so that the regulatory framework will be more efficient in the future.[13]

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11 Decision 2009-035, pages 41-48.

12 Transcript, Volume 1, page 197, lines 11 to 22, Dr. Makholm.

13 The generic cost of service proceedings is discussed in Section 16.

1.3 Performance-based regulation preparations

26. In its February 26, 2010 letter, the Commission invited interested parties to assist the Commission in determining the scheduling and the scope of issues for PBR implementation. The Commission held a roundtable with 18 interested parties on March 25, 2010 to discuss steps for the implementation of PBR.[14] The companies objected to the Commission's stated preference that PBR begin on July 1, 2011. The companies asked for more time to prepare for PBR and to file rate cases to establish their going-in rates for PBR, a process that would take some time. In addition, during the roundtable, participants agreed that the Commission should conduct a workshop so that the participants could become more familiar with the theory of and experience with PBR. Participants also agreed that the Commission should initiate a short proceeding to establish common principles to guide and assess PBR proposals to be subsequently filed by Alberta distribution companies within the Commission's jurisdiction.

27. In its April 9, 2010 letter[15] the Commission announced that in response to requests by participants, it had engaged the Van Horne Institute to conduct an independent PBR workshop on May 26 to 27, 2010 in order to educate participants about the issues, terminology and concepts raised by PBR. Participants were informed that the information provided and views expressed at the workshop did not necessarily represent the views of the Commission. Ninety-two people representing all of the utility companies and intervener groups attended the workshop.

28. Also, in its letter of April 9, 2010, the Commission initiated a proceeding to solicit comments on the principles that should guide the development of PBR in Alberta. The proceeding commenced on June 10, 2010 with submissions from the various parties and closed on June 24, 2010 with the submission of reply comments.[16] The Commission reviewed these submissions, and in Bulletin 2010-20,[17] dated July 15, 2010, the Commission found that there was general agreement on the following five principles:[18]

> **Principle 1.** A PBR plan should, to the greatest extent possible, create the same efficiency incentives as those experienced in a competitive market while maintaining service quality.
>
> **Principle 2.** A PBR plan must provide the company with a reasonable opportunity to recover its prudently incurred costs including a fair rate of return.
>
> **Principle 3.** A PBR plan should be easy to understand, implement and administer and should reduce the regulatory burden over time.
>
> **Principle 4.** A PBR plan should recognize the unique circumstances of each regulated company that are relevant to a PBR design.
>
> **Principle 5.** Customers and the regulated companies should share the benefits of a PBR plan.

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14 See Attachment 1 of Exhibit 6.01 for a list of participants, page 2.
The following parties suggested clear objectives before instituting PBR: AltaLink, page 1; ATCO, page 1; Calgary, Principle 1, page 3; UCA, page 1; IPCAA, Principle 1, page 1.

15 Exhibit 6.01, AUC letter of April 9, 2010.

16 Appendix 1 of Bulletin 2010-20 lists the parties who made submission and the associated exhibit numbers.

17 Bulletin 2010-20, Regulated Rate Initiative – PBR Principles, July 15, 2010.

18 Exhibit 64.01, Appendix 2 of Bulletin 2010-20 lists references of parties with similar principles in their submissions.

29. The gas and electric distribution companies present at the March 25, 2010 roundtable (other than ENMAX) agreed that they could each file a PBR proposal by the end of the first quarter of 2011. Therefore, in Bulletin 2010-20, the Commission directed these gas and electric distribution companies to file their PBR proposals by March 31, 2011. The distribution companies that are also transmission facility owners could choose whether or not to include their transmission operations in their proposed PBR plans. Parties were required to explain how their PBR proposals were consistent with the Commission's five principles for PBR and how their proposals would satisfy the Commission's objectives for PBR.

30. On September 8, 2010, the Commission notified the parties that it had retained National Economic Research Associates (NERA) to prepare a total factor productivity (TFP) study that could be used as the basis for determining an X factor in a PBR plan for the electricity and natural gas distribution industries.[19] The NERA TFP study was to be filed by December 31, 2010.[20] The filing date for the companies' PBR proposals was later changed to July 26, 2011, in order to allow the companies sufficient time to consider the evidence to be filed by NERA, with the objective being to implement PBR effective January 1, 2013.[21]

1.4 Overview of PBR proposals and the Commission's approach

31. In Bulletin 2010-20[22] that established the PBR principles, the Commission also provided the following guidance to the companies and interveners:

> In the Commission's opinion, a PBR plan consisting only of an I - X formula would, to the greatest extent possible, mimic the efficiency incentives of competitive markets provided that the X factor requires the company to achieve annual productivity improvements at least equivalent to those of the relevant industry. Therefore, the Commission expects each proposal to include I - X as part of the PBR plan. Some parties proposed principles that dealt with certain aspects of various PBR plans such as exogenous adjustments, earnings sharing, the term of the plan, capital adjustments, reporting requirements and rate structure changes, among others. In the Commission's opinion, these are more properly considered as potential elements of a PBR plan and are not principles. In making their proposals, companies may choose to include these or other elements in order to address circumstances resulting from Alberta's market structure, the industries in which the companies operate, unique company-specific circumstances or other circumstances that may be relevant. Companies are expected to fully explain the circumstances that give rise to the need for each element, how each element addresses that need and how each element is justified by the principles and objectives of PBR.[23]

32. The companies filed their PBR proposals on July 26, 2011. Interveners filed their PBR evidence on December 16, 2011.

33. The Commission received a wide range of proposals from the companies and the interveners. Parties agreed with the Commission's objectives and principles and, for the most part, fashioned their PBR proposals to be consistent with them. The Office of the Utilities

[19] Exhibit 71.01, AUC letter – Retention of Consultant to Develop a Basic X Factor.
[20] Exhibit 80.02, NERA first report.
[21] Please see Appendix 3 for details of the procedural steps.
[22] Exhibit 64.01, AUC Bulletin 2010-20.
[23] Exhibit 64.01, Bulletin 2010-20, page 3.

Consumer Advocate (UCA) expressed concerns about moving to PBR at this time.[24] The UCA's position was that the companies are performing well under the current cost of service framework and that more company-specific information is needed to implement the type of PBR plan that the UCA envisions. The Industrial Power Consumers Association of Alberta (IPCAA) recommended a limited adoption of PBR until two types of performance metrics (quality of service and asset condition metrics) are available and the necessary quality and reliability safeguards are implemented.[25] EPCOR proposed a PBR plan that excludes all capital-related costs from the application of an I-X mechanism.[26] The other parties (ATCO Electric,[27] ATCO Gas,[28] Fortis,[29] AltaGas,[30] the Consumers' Coalition of Alberta (CCA)[31] and The City of Calgary (Calgary)[32]) proposed or accepted plans that applied an I-X mechanism to all categories of costs. Each of these parties also argued for or accepted some type of provision to deal with some capital costs outside of the I-X mechanism and proposed or accepted the need for certain new or existing deferral accounts and rate riders.

34. In seeking to develop a PBR mechanism that can best achieve the Commission's objectives while being consistent with all of its principles to the maximum extent possible, the Commission has carefully considered all of the submissions of the companies and interveners. The Commission is employing an I-X mechanism and a five-year term as part of its PBR plan in order to create the same efficiency incentives as those that are present in competitive markets to the greatest extent possible for the electric and gas distribution companies. The inclusion of an efficiency carry-over mechanism will further enhance these incentives. In doing so, the Commission is also making provision for the exclusion of some capital costs from application of the I-X mechanism where necessary in order to accommodate the unique circumstances of each regulated company. The Commission is employing a revenue-per-customer cap for natural gas distribution companies and a price cap for electric distribution companies in order to recognize the differences between those two industries. The Commission is also making provision for the treatment of necessary deferral accounts and flow-through mechanisms for each company as part of its PBR plan.

35. In making its determinations, the Commission has considered the effect of the combination of the I-X mechanism with the treatment of some capital-related costs outside of the I-X mechanism, the Z factor adjustments and the provision for deferral accounts and flow-throughs to protect the companies from significant unforeseen events that are outside their control. In addition, the Commission has considered the statements of a number of witnesses regarding the incentives to over-forecast capital expenditures, the observation of Dr. Lowry that the companies have considerable flexibility in the timing of capital replacements[33] and the views of Dr. Weisman that with the incentives created by the plan, the companies will discover new ways to conduct their businesses.[34] Having considered the statements of the parties and

[24] Exhibit 299.02, Cronin and Motluk UCA evidence, pages 12-13.
[25] Exhibit 306.01, IPCAA Vidya Knowledge Systems evidence.
[26] Exhibit 103.02, EPCOR application.
[27] Exhibit 98.02, ATCO Electric application.
[28] Exhibit 99.01, ATCO Gas application.
[29] Exhibit 100.01, Fortis application.
[30] Exhibit 110.01, AltaGas application.
[31] Exhibit 307.01, CCA evidence.
[32] Exhibit 298.02, Calgary evidence.
[33] Exhibit 307.01, CCA evidence of PEG, Section 4.1, page 59; Exhibit 636.01, CCA argument, Section 8.1, paragraph 118.
[34] Exhibit 103.03, EPCOR application, Appendix A, page 20, paragraph 49.

witnesses, and the full record of the proceeding, the Commission is satisfied that the PBR plans approved in this decision will provide each of the companies with a reasonable opportunity to recover its prudently incurred costs including a fair rate of return over the five-year term of the plan. With regard to earning a fair rate of return, there was general agreement[35] among the experts and the parties that the opportunity to earn a fair rate of return should be considered over the term of the PBR plan and not on a year-by-year basis.

36. Customers will share the benefits from the improved efficiency incentives under PBR through the inclusion of an X factor and a stretch factor in the plan. Customers will be protected against earnings significantly above the approved ROE, and the companies will be protected against earnings significantly below the approved ROE, by the incorporation of a re-opener in the plan. If the ROE of a company meets the conditions for a plan re-opener to take effect, this will afford an opportunity for the Commission to re-examine the parameters of the plan and, if required, to adjust them.

37. The Commission is also making provision for enhanced quality of service rules and measures to address the incentive that companies might have to reduce their costs in such a way that service quality declines in the short and long term.

38. The Commission has sought to make the PBR plans as easy to understand, implement and administer as possible given the structure of the electric and natural gas industries in Alberta, the need to accommodate the unique circumstances of each company and the recognition that this is the first time PBR has been adopted for all of the distribution companies. The Commission is confident that as the parties become more familiar with PBR and as the companies discover new ways to adapt their businesses to the opportunities PBR offers, it will be possible to further streamline the regulatory framework to achieve the Commission’s objectives.

39. Finally, the Commission is satisfied that the PBR plans meet the objectives for PBR described in its February 26, 2010 letter. Furthermore, the Commission has taken particular note of the five PBR principles articulated in Bulletin 2010-20. The Commission is satisfied that the PBR plans overall, and each of the elements of the plans, are consistent, to the maximum extent possible, with all five principles.

40. The Commission intends to review PBR as it comes to the end of the first term and to consider extending the plans or incorporating other approaches if those can be demonstrated to better balance regulatory efficiency and regulatory effectiveness in a way that achieves the Commission’s objectives and satisfies the Commission’s principles.

2 Approaches to rate regulation

41. The UCA (Office of the Utilities Consumer Advocate), IPCAA (Industrial Power Consumers Association of Alberta), and EPCOR each proposed alternatives to the Commission’s preferred approach to PBR (performance-based regulation) stated in its letter of February 26, 2010 and Bulletin 2010-20. These proposals affected either the time at which PBR could be implemented in Alberta for the electric and gas distribution companies, the nature of PBR, or the

35 Transcript, Dr. Carpenter, Volume 3, pages 565-566; Transcript, Mr. Camfield, Volume 8, page 1373; Transcript, Mr. Gerke and Dr. Weisman, Volume 10, pages 1828-1829; Transcript, Ms. Frayer, Volume 11, page 2190.

costs to which PBR would apply. In this section, the Commission addresses each of these alternative proposals. The Commission also addresses specific elements of these proposals throughout this decision.

2.1 The UCA's proposal

42. The UCA proposed a delay in the implementation of PBR. The UCA developed its own objectives for PBR and then used those objectives, in combination with its view of what a PBR plan should be like, to justify the delay.

43. The UCA's objectives were expressed as follows:

- Better economic incentives in order to achieve productivity improvements, which will result in lower customer rates than under cost of service regulation,
- Clearly defined performance standards with penalties for failure to achieve specified performance targets, and
- A reduction in the overall regulatory burden by improving the efficiency of the regulatory framework.[36]

44. The UCA stated that if PBR would not meet its three over-arching objectives, then the move to PBR at this time must be reassessed. The UCA also submitted that based on the available information, there is no compelling reason to switch to PBR. Three principal reasons were given for this position:

1) The evidence of Dr. Cronin [expert witness for the UCA] that regulatory burden does not go down under PBR;
2) The large capital forecasts upon which the applicants' PBR plans are based, and, in the case of EDTI the complete exclusion of capital from its PBR plan; and
3) The lack of information presently available about the applicants: (i) comparative performance; (ii) present efficiency levels, and (iii) potential for efficiency improvements.[37]

Commission findings

45. The Commission has considered the UCA's objectives for PBR and its reasons for reassessing the move to PBR at this time. The Commission agrees with the objectives that PBR should provide better economic incentives and result in lower rates than under cost of service regulation. The Commission also agrees that PBR should reduce the regulatory burden by improving the efficiency of the regulatory framework. The Commission considers that clearly defined performance standards and the imposition of penalties to achieve performance targets is a good approach to addressing service quality issues, and, therefore, the Commission has included maintaining service quality as an integral part of its first PBR principle. Service quality issues and the Commission's approach to maintaining service quality are addressed in Section 14 of this decision.

46. The Commission acknowledges the UCA's concerns about the capital forecasts filed by the companies in this proceeding and has addressed these concerns in this decision.

[36] Exhibit 634.01, UCA argument, paragraph 20, page 4.
[37] Exhibit 634.01, UCA argument, paragraph 28, page 5.

47. The Commission considers the UCA's first and third reasons for reconsidering and delaying implementation of PBR at this time to be closely related. Dr. Cronin argued that the regulatory burden does not go down under PBR and cites the Ontario PBR plans as an example. In the Commission's view, the type of PBR plan envisioned by Dr. Cronin would not decrease the overall regulatory burden because significant effort would still be required, although on different matters than under cost of service regulation. Dr. Cronin expressed his view that PBR plans require collecting significant amounts of information in order to carry out comparisons of the productivity and efficiency performance of various individual companies in Alberta with each other and with other North American companies. Dr. Cronin requires this information in order to determine how close those companies are to the "efficiency frontier"[38] and, therefore, their potential for efficiency improvements.[39] In addition, Dr. Cronin argued for the use of company-specific total factor productivity studies (which is also a data-intensive undertaking) to establish company-specific X factors. Dr. Cronin further suggested that comparisons of companies could be made at even more disaggregated levels, such as individual cost types or cost centres.[40]

48. In the Commission's view, adopting this type of an approach to PBR might very well increase the regulatory burden. Indeed, Dr. Cronin, in describing the approach used in Great Britain (one that appears to require the same type of information as that proposed by Dr. Cronin), stated that the regulator there "busies hundreds of analysts"[41] to give effect to its regulatory approach.

49. It is not the Commission's intention to build a PBR regulatory framework that requires or invites the Commission to manage the companies through analysis of and distinct incentive schemes for lower level cost data provided in company-specific TFP studies. Nor is it the Commission's intention to benchmark companies against each other or against an estimated efficiency frontier. In the ENMAX proceeding, Dr. Cronin expressed similar views to those expressed in this proceeding, and the Commission rejected them in Decision 2009-035, dealing with the ENMAX FBR proposal.[42] The Commission's objective is to provide incentives for improved efficiencies, both in the short run and the long run, as well as opportunities for the companies, without Commission direction and control, to discover and implement those efficiencies over longer time periods than they would have under the current regulatory framework. In the Commission's view, the PBR approach envisioned by the UCA would not achieve the objective of improving the efficiency of the regulatory process, nor would it satisfy the principle that**,** to the greatest extent possible, a PBR plan should create the same efficiency incentives as those experienced by companies in a competitive market. It would also not satisfy the principle that a PBR plan should be easy to understand, implement and administer and should reduce the regulatory burden over time.

50. The Commission has also considered the UCA's view that PBR need not be implemented at this time because "based on the limited information available, it appears very likely the applicant utilities have superior performance, their rates are below or equal to other jurisdictions; their reliability is higher; and ROE is much higher than other jurisdictions."[43] The UCA's

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[38] For further discussion on the efficiency frontier approach please refer to Section 6.2.
[39] Exhibit 634.01, UCA argument, paragraph 40, page 7.
[40] Transcript Volume 18, page 3420, line 8 to page 3422, line 7.
[41] Transcript, Volume 17, pages 3227, lines 15-16; Transcript, Volume 18, pages 3430-3431.
[42] Decision 2009-035, paragraph 175.
[43] Exhibit 634.01, UCA argument, paragraph 48, page 9.

conclusion is based on a benchmarking of the Alberta companies to a number of U.S. local distribution companies selected by Dr. Cronin.[44] These comparisons show that ENMAX's and EPCOR's local distribution rates are at the lower end of the range of rates of the selected companies and that Fortis is in the range of two local distribution companies in the northern states.[45] Information provided in response to an undertaking showed that ATCO Electric's local distribution rates are much higher than the other companies in the UCA's comparison group.[46]

51. The Commission is not satisfied that these comparisons can justify a decision to delay PBR until more information can be provided and analysed. ENMAX's rates are already regulated under a PBR plan. EPCOR has explained that a great deal of its local distribution network is in need of replacement. As a result, its rates can be expected to be lower because its capital-related costs included in rates will be lower than if the local network had already been substantially replaced. Indeed, as discussed in Section 7.3, the Commission's observation in this proceeding is that differences among the companies' capital proposals under PBR can be explained to some degree by where those companies are in the long term cycle of capital investment and replacement. Furthermore, this observation makes suspect the results of benchmarking across different regulated companies, whether Canadian companies or, as in the UCA analysis, U.S. companies. There may also be significant differences among the companies that cannot be accounted for in benchmarking studies.

52. Accordingly for all of the reasons stated above, the Commission is not persuaded by the UCA to reconsider or delay implementation of PBR for Alberta distribution companies.

53. The UCA has proposed that if the Commission proceeds at this time with PBR, it should engage in benchmarking and, if not benchmarking, then it should use a menu approach to PBR. If the menu approach is not employed by the Commission, the UCA recommended that the Commission adopt the ENMAX FBR model. The UCA's proposal for benchmarking and its menu approach to PBR are both addressed Section 6.2.

2.2 IPCAA's proposal

54. IPCAA objected to the full implementation of PBR at this time. IPCAA proposed the use of an I-X mechanism only for general and administrative (G&A) costs and the retention of cost of service regulation for the remaining costs (O&M (operating and maintenance) as well as capital-related costs). IPCAA's concern is that PBR creates incentives to reduce costs and that the Commission's current quality of service rules are not sufficient to protect service quality and asset condition. IPCAA, therefore, recommended a limited adoption of PBR until specific quality of service and asset condition performance metrics are implemented.[47]

Commission findings

55. The Commission understands IPCAA's concerns about the potential effects of the incentives created by PBR on service quality and the condition of the companies' capital assets. The Commission also recognizes that its own current quality of service rules may not be sufficient to properly address IPCAA's concerns or, indeed, the Commission's concerns under PBR. However, the Commission does not agree that these concerns must be addressed before a

[44] Exhibit 299.02, Cronin and Motluk UCA evidence, page 27.
[45] Exhibit 299.02, Cronin and Motluk UCA evidence, page 27; Exhibit 614.01, UCA undertaking.
[46] Exhibit 614.01, undertaking response given by Dr. Cronin.
[47] Exhibit 304.01, IPCAA policy evidence.

PBR plan can begin. The Commission is confident that its plans to address service quality and asset condition issues early in the PBR term will be sufficient to allow PBR to proceed. The Commission has taken into account IPCAA's concerns in its quality of service determinations and plans described in Section 14.

56. Furthermore, the Commission notes that IPCAA's proposal to include only G&A expenses in PBR would result in a negative effect on incentives because of the exclusion of a significant portion of the operations of a company from the I-X mechanism. Such an effect is well documented in this proceeding.[48] Therefore, based on all of the above, the Commission does not accept IPCAA's suggestion to limit the PBR plans to G&A expenses only.

2.3 EPCOR's proposal to exclude capital

57. EPCOR has proposed to exclude all capital-related costs from the application of the I-X mechanism.[49] The reason given by EPCOR is that it must embark on a major capital replacement program to address its aging local distribution system. EPCOR argued that, in its case, including all current capital-related expenses under the I-X mechanism and making provision for its significant capital additions outside of the I-X mechanism would be too complex to implement and could prevent EPCOR from making efficient capital decisions because of the way in which a capital mechanism outside of the I-X mechanism might be structured.

Commission findings

58. The Commission understands EPCOR's concerns but is itself concerned that excluding all capital from the I-X mechanism will not create new incentives to more optimally make efficient trade-offs between capital and maintenance and may serve to exacerbate the already significant incentives under a rate base rate-of-return framework to prefer capital investment over O&M expenses. In addition, the Commission is not satisfied that there is any acceptable way to create an X factor suitable for use for non-capital-related costs only. Therefore, the Commission does not accept EPCOR's proposal to exclude all capital-related costs from application of the I-X mechanism. However, the Commission does address EPCOR's concerns about how its capital program can be treated outside of the I-X mechanism in Section 7.3.2.4 of this decision.

2.4 EPCOR's transmission proposal

59. In its February 26, 2010 letter, the Commission indicated that reform of rate regulation for electricity and natural gas transmission services would not be undertaken at that time because:

> The electricity transmission system is entering a period of significant change with substantial planned expansions while natural gas transportation rates are one subject of more extensive negotiations between the province's two largest regulated natural gas transportation service providers.[50]

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[48] Transcript, Volume 1, page 143, Dr. Makholm.
[49] Exhibit 103.02, EPCOR application, pages 10-18.
[50] Exhibit 1.01, AUC letter dated February 26, 2010, Rate regulation initiative round table.

60. Nonetheless, on July 15, 2010, the Commission released Bulletin 2010-20, which stated that "those distribution companies that are also transmission facility owners may choose to include their transmission components in the PBR plan if that is their preference."[51]

61. Of the Alberta distribution companies affected by the bulletin that also had an integrated transmission function, EPCOR was the only company that proposed to include its transmission component in its PBR plan. EPCOR explained that the highly integrated nature of its distribution and transmission functions allowed for economies of scale and scope and that a single, joint rate application for the two business operations reduced regulatory burden.[52]

62. As further outlined in the subsequent sections of this decision, EPCOR proposed that in its PBR plan, the I-X mechanism would apply only to the company's O&M and other non-capital costs, with capital expenditures treated as a flow-through item. EPCOR proposed this type of PBR plan for both its distribution and transmission functions.[53] In these circumstances, as discussed in Section 6.4.3, Dr. Cicchetti noted that an X factor for EPCOR should reflect the changes in O&M productivity only. Furthermore, because the O&M costs of EPCOR's distribution and transmission functions were similar in nature, Dr. Cicchetti offered that his recommended X factor was relevant to both functions:

> The two functions are highly integrated and interdependent, with shared management and staff, who utilize the same offices and other assets. There are common union settlements and the primary O&M input for both functions is labour. Accordingly, my recommendations apply to both functions.[54]

63. In its proposed PBR plan, EPCOR included four service quality performance measures and proposed targets for each of these measures along with a penalty adjustment in its formula for non-compliance with the performance targets. The four service quality performance measures were: Total Recordable Injury Frequency Rate (TRIF), System Average Interruption Frequency Index (SAIFI), System Average Interruption Duration Index (SAIDI) and Service Connection Time (SCT).[55] For three of these measures, TRIF, SAIDI and SAIFI, EPCOR proposed to report combined distribution and transmission results.[56] During the hearing, EPCOR witnesses testified that there are no service quality issues that are unique to transmission.[57] As such, EPCOR concluded that its proposed service quality measures that combine distribution and transmission are "reasonable and workable."[58]

64. No party to this proceeding opposed the inclusion of EPCOR's transmission function in the company's PBR plan. However, the CCA and IPCAA expressed their concerns with the lack of relevant reliability metrics for transmission in Alberta to be used as service quality performance measures in PBR plans for electric transmission operations.

65. In argument and reply, IPCAA pointed to the absence of standard province-wide service quality measures for electric transmission services in Alberta. In IPCAA's view, a PBR

51 Exhibit 64.01, AUC Bulletin 2010-20, page 3.
52 Exhibit 103.02, EPCOR application, paragraph 14.
53 Exhibit 103.02, EPCOR application, paragraph 3.
54 Exhibit 103.05, Cicchetti evidence, pages 20-21.
55 Exhibit 630.02, EPCOR argument, paragraph 292.
56 Exhibit 630.02, EPCOR argument, paragraph 309.
57 Transcript, Volume 10, page 1813, lines 17-21.
58 Exhibit 646.02, EPCOR reply argument, paragraph 283.

mechanism for transmission facilities would be "far more complex and have much greater impact than at the distribution level," since the consequences of service quality degradation for transmission are much more severe than for distribution:

> Reductions in customer service quality at a POD [point-of-delivery where the distribution system connects to the transmission system] level will have an order of magnitude larger impact as transmission level outages affect either thousands of smaller customers at a [distribution company] point of delivery or large industrial facilities such as gas plants, refineries and oil sands facilities.[59]

66. Accordingly, IPCAA asserted that transmission service quality measures should be considered in a province-wide process. In IPCAA's view:

> Applying PBR to EDTI's transmission function could result in a piecemeal approach to transmission regulation, which is managed and delivered on a province-wide basis, and typically consists of large, capital intensive projects, the costs of which are flowed through to customers.[60]

67. The CCA expressed concern over the lack of data that EPCOR proposed to report in relation to transmission reliability and proposed that the Commission direct EPCOR to also report additional reliability measures such as energy not supplied, average interruption time and overhead line maintenance cost index for its transmission reliability. The CCA indicated that these measures are being used by other transmission companies.[61]

Commission findings

68. The Commission has two concerns with EPCOR's proposed inclusion of its transmission function under its PBR plan.

69. First, EPCOR's proposed X factor, which would be applicable to both its distribution and transmission functions under its PBR plan, is only for non-capital costs. Dr. Cicchetti stated that because the O&M costs of EPCOR's distribution and transmission functions were similar in nature, his recommended X factor (calculated using the O&M data for the distribution component of NERA's sample) was relevant to both functions.[62] In the Commission's view, it is uncertain whether the same conclusion can be reached when the X factor is calculated based on the entirety of the costs (both O&M and capital) of the company.

70. In its productivity study, NERA measured the TFP of the distribution component of 72 U.S. electric and combination electric/gas companies from 1972 to 2009. Costs related to power generation and transmission, as well as general overhead costs, were not included in the study.[63]

71. As explained above, the Commission has not accepted EPCOR's proposal to exclude capital and apply the I-X mechanism only to the O&M and other non-capital costs in its PBR plan. No evidence was filed in this proceeding on what the relevant X factor for the electric transmission function should be if the I-X mechanism is applied to both O&M and capital costs.

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59 Exhibit 635.01, IPCAA argument, paragraph 75.
60 Exhibit 642.01, IPCAA reply argument, paragraph 38.
61 Exhibit 636.01, CCA argument, paragraphs 363-365.
62 Exhibit 103.04, Cicchetti evidence, pages 20-21.
63 Exhibit 80.02, NERA report, page 6.

Accordingly, the Commission cannot set an X factor for EPCOR if the transmission function is included in the plan.

72. Second, EPCOR's proposed measures, targets and penalties to ensure service quality were proposed in the context of a PBR plan that excludes capital-related costs from the rates subject to the I-X mechanism. It is unclear whether these measures, targets and penalties would be adequate to ensure transmission service quality for a PBR plan that is not restricted in this manner. EPCOR's proposals for service quality measures are further discussed in Section 14.

73. The creation of reliability standards and performance targets for transmission is still under development. Unlike transmission, the Commission has been monitoring service quality performance through AUC Rule 002[64] for electric utilities and gas distributors. While further measures and performance targets will be developed as part of AUC Rule 002, as discussed in Section 14, there has been a history of measuring and reporting performance for the distribution function with which companies and industry stakeholders are familiar. There is no similar starting point for transmission.

74. In light of the above considerations, the Commission finds that transmission services should not be a part of EPCOR's PBR plan. EPCOR's transmission services will continue to be regulated under cost of service regulation.

3 Going-in rates

3.1 Purpose and background

75. Going-in rates are the starting rates for the implementation of a PBR (performance-based regulation) plan. The going-in rates are sometimes referred to as "year zero rates." They are the rates to which the approved PBR formula is applied to determine the rates to be charged to customers during the first year of the PBR term. Thereafter, the current year's rates are adjusted by the PBR formula to determine the upcoming year's rates until the end of the PBR term.

76. In Decision 2009-035,[65] the Commission determined that ENMAX's going-in rates were to be based on the company's revenue requirement as determined in a forecast cost of service rate setting proceeding.[66] The Commission directed that the going-in rates for ENMAX would be its approved 2006 rates, adjusted to include previously disallowed short term incentive plan costs. With respect to adjustments to going-in rates proposed by ENMAX and interveners to reflect certain actual 2006 costs, the Commission stated that it would "not accept adjustments to the going-in rates to account for 2006 actual results."[67] The Commission further stated that: "[a]djustments to account for actual results should not be made selectively but, rather, should only be made in the context of a full rate case which would consider the forecast costs for a subsequent time period."[68] The Commission accepted a single adjustment to going-in rates to include previously disallowed short term incentive plan costs. This adjustment was approved on

[64] AUC Rule 002: *Service Quality and Reliability Performance Monitoring and Reporting for Owners of Electric Distribution Systems and for Gas Distributors*, effective July 1, 2010 (Rule 002).

[65] Decision 2009-035: ENMAX Power Corporation, 2007-2016 Formula Based Ratemaking, Application No. 1550487, Proceeding ID. 12, March 25, 2009.

[66] Decision 2009-035, paragraph 72.

[67] Decision 2009-035, paragraph 73.

[68] Decision 2009-035, paragraph 74.

the basis that ENMAX had addressed the concerns that had led to the original disallowance of these costs from inclusion in the 2006 revenue requirement and that the revised short term incentive plan had been designed to incent "operational efficiency improvements and, as such, complements the incentives created by a formula based regulation plan."[69]

77. In a December 16, 2010 letter granting deadline extensions for the filing of the companies' PBR proposals in this proceeding, the Commission determined that the forthcoming rate decisions for the 2012 test year will be used by the Commission to establish the going-in rates for the companies.

3.2 Proposals for going-in rates

78. All of the companies proposed that their 2012 approved rates be used as the basis for their going-in rates. In addition, all of the companies, with the exception of EPCOR, proposed adjustments to their 2012 approved rates in setting going-in rates for the PBR term. The companies collectively proposed a total of nine individual adjustments to their going-in rates. Like ATCO Electric and ATCO Gas, AltaGas stated that its adjustments were necessary to earn a fair rate of return during the PBR plan.[70]

79. EPCOR pointed to Decision 2009-035 in proposing that its 2012 approved distribution and transmission tariffs be used as the going-in rates for the company's PBR plan[71] without adjustment. In UCA-EDTI-10(b) EPCOR stated:

> The approved distribution rates and transmission revenue requirement will form EDTI's going-in rates and revenue requirement and, for many of the same reasons stated by the Commission in Decision 2009-35 [sic.], no adjustments to those rates for PBR purposes will be necessary or warranted. If the rates and revenue requirement are just and reasonable for 2012, they will also be just and reasonable as EDTI's going-in rates and revenue requirement. As the Commission indicated in Decision 2009-035, costs and financial results will fluctuate from year to year over the PBR Term. In some years, costs will be higher than expected and in other years lower, EDTI will be incented to improve its efficiency and productivity and under EDTI's PBR Plan, some of these gains will be shared with customers and some will be retained by EDTI.[72]

80. AltaGas requested that its going-in rates be based on its 2012 distribution rates approved in response to its 2010 to 2012 GRA (general rate application) subject to certain adjustments. ATCO Electric and ATCO Gas proposed to use their 2012 final distribution rates as the basis for the going-in rates for the PBR term subject to certain adjustments.[73] Fortis also proposed to use its 2012 approved rates as the basis for its going-in rates but requested that the rates be adjusted to reflect its 2013 opening rate base balance, which would recognize 2012 actual capital expenditures.[74]

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69 Decision 2009-035, paragraph 79.

70 Exhibit 628.01, AltaGas argument, page 81; Exhibit 628.01, AltaGas argument, page 80; Exhibit 389.01, ATCO Gas update, page 4, paragraph 7.

71 Exhibit 103.02, EPCOR application, page 2.

72 Exhibit 238.01, EPCOR information responses, pages 25 and 26.

73 Exhibit 98.02, ATCO Electric application, paragraph 208 and Exhibit 99.01, ATCO Gas application, paragraph 10.

74 Exhibit 100.02, Fortis application, page 11.

81. There were no objections by interveners to the companies' proposals that the 2012 approved rates be used as the starting point for going-in rates in the PBR term. The CCA stated that, for the purposes of going-in rates, the approved revenue requirements have been set by rigorous cost of service regulatory oversight. However, the CCA stated that it was uncertain of the finality of these revenue requirements because of placeholders or the potential impact of other adjustments for outstanding appeals or applications.[75]

82. The UCA recommended that the "going-in rates must include recognition of efficiency gains achieved in the last cost of service test period."[76] IPCAA and the CCA did not provide argument on going-in rates but agreed with the UCA that efficiency gains achieved under cost of service regulation should be recognized in going-in rates.[77]

Commission findings

83. Prior to initiating the current proceeding, the Commission considered two alternatives for establishing the going-in rates at the commencement of the PBR term. The first alternative was to use the actual results for the immediately preceding year, in this case 2012, and adjust the 2012 approved rates to reflect the actual 2012 results to form the basis for the going-in rates for PBR. This approach would account for any expenses that were not forecast in the 2012 revenue requirement and any unaccounted for efficiency gains realized in 2012, all subject to a prudency review. However, the Commission recognized that the actual results for 2012 would not be available until well into 2013 and that a prudency review of these results would require a significant regulatory process. The Commission did not adopt this approach because it is inconsistent with the Commission's objective to implement PBR effective January 1, 2013 as set out in the Commission's letter of December 16, 2010.[78]

84. The other alternative was to adopt the approach approved in Decision 2009-035 which uses rates approved in the most recent revenue requirement proceeding as the basis for establishing the going-in rates.

85. In an effort to promote regulatory efficiency, and so as not to delay the commencement of PBR, the Commission in its December 16, 2010 letter, adopted the approach approved in Decision 2009-035 and directed that the companies' approved rates for 2012 would be used as the basis for establishing going-in rates. Accordingly, rates that will form the basis for the going-in rates for PBR will have been established in the context of a full rate case, or in the case of Fortis, on the basis of a negotiated settlement approved by the Commission.

86. With respect to proposed adjustments to going-in rates, the Commission again has two alternatives. The first alternative is to consider making adjustments to include certain costs that were either not forecast or otherwise approved for inclusion in the 2012 revenue requirement, as proposed by certain of the companies. In this context, the Commission could also consider an adjustment to going-in rates to reflect efficiency gains that may have occurred in 2012 that were not already reflected in 2012 approved rates, as proposed by interveners.

[75] Exhibit 636.01, CCA argument, paragraph 11.
[76] Exhibit 634.01, UCA argument, page 72.
[77] Exhibit 642.01, IPCAA reply argument, paragraph 62.
[78] Exhibit 79.01, AUC letter dated December 16, 2010, Request for deadline extensions.

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87. The second alternative is to again adopt the approach followed in Decision 2009-035. In that decision the Commission rejected the adjustments to going-in rates proposed by ENMAX and interveners to reflect certain actual 2006 costs. The Commission stated that it would "not accept adjustments to the going-in rates to account for 2006 actual results."[79] The Commission further stated that: "[a]djustments to account for actual results should not be made selectively but, rather, should only be made in the context of a full rate case which would consider the forecast costs for a subsequent time period."[80] The Commission did accept however, a single adjustment to going-in rates to include previously disallowed short term incentive plan costs. This adjustment was accepted on the basis that ENMAX had addressed the concerns that had led to the original disallowance of these costs from inclusion in the 2006 revenue requirement and that the revised short term incentive plan had been designed to incent "operational efficiency improvements and, as such, complements the incentives created by a formula based regulation plan."[81] The Commission found that an adjustment of this kind "is qualitatively different from rate adjustments made after the fact to reflect actual results."[82]

88. The Commission considers the second alternative is in keeping with the decision to use 2012 approved rates rather than 2012 actual costs as the basis for going-in rates. The 2012 rates have been tested and approved by the Commission as just and reasonable for 2012. Accordingly, the 2012 approved rates are the correct starting point on which to base going-in rates. The Commission confirms the findings in Decision 2009-035 that adjustments to going-in rates should not be made to reflect actual results. Further, adjustments should not be made selectively but, rather, should only be made in the context of a full rate case. Adjustments may be made in exceptional situations, however, like the case of the short term incentive plan adjustment approved in the ENMAX decision.

89. Accordingly, the Commission will consider adjustments that are in the nature of a correction to the going-in rates, and which are not rate adjustments made after-the-fact to reflect actual results. This approach is consistent with the Commission's finding in Section 7.4.4 that differences between placeholder amounts and final approved amounts will be treated as Y factor adjustments or adjustments to rates that will be subject to the I-X mechanism, depending on the circumstances of the adjustment.

90. The Commission will consider each of the proposals of the companies and interveners to include adjustments to going-in rates.

91. Given the above findings, the Commission directs the companies to use their respective approved 2012 distribution rates as the going-in rates for the PBR term, subject to the specific adjustments allowed below.

3.3 Requests for adjustments to going-in rates

3.3.1 UCA requested adjustment for efficiency gains

92. The UCA recommended that efficiencies achieved by the companies prior to the commencement of the PBR term should be reflected in going-in rates. The UCA stated that prior to the implementation of PBR, the utilities had undertaken projects that will create new

[79] Decision 2009-035, paragraph 73.
[80] Decision 2009-035, paragraph 74.
[81] Decision 2009-035, paragraph 79.
[82] Decision 2009-035, paragraph 81.

efficiencies. However, none of the applications included any "mechanism or adjustment to allow customers to benefit from these efficiencies in going-in rates."[83]

93. The UCA identified two specific adjustments for ATCO Gas to account for efficiency gains: one to remove the costs of old facilities from going-in rates and one to remove certain costs for meter reading to account for the adoption of automated meter reading in 2012.[84]

94. IPCAA and the CCA agreed with the UCA that efficiency gains achieved under cost of service regulation should be recognized in going-in rates.[85]

95. EPCOR disagreed with the UCA's proposed adjustments to going-in rates for efficiencies achieved under cost of service regulation and pointed to its actual return on equity being close to or below the target ROE.[86] The ATCO companies argued that the 2011 to 2012 distribution rates proceedings included a forecast of anticipated productivity improvements. The ATCO companies argued, "there is a danger that any adjustment could be giving customers the benefit of those productivity improvements twice, because they have already been incorporated into the 2012 going-in revenue for PBR."[87]

Commission findings

96. As stated in Section 3.2 above, it is the Commission's view that adjustments to going-in rates should not be made to reflect actual costs incurred in the test year which form the basis for the going-in rates. Adjustments should only be made in the context of a full rate case. Accordingly, the Commission denies adjustments to reflect possible efficiency gains in a prior period that are not captured in the going-in rates. This finding is consistent with the Commission's determination in Decision 2009-035 which denied the UCA's request to reduce going-in rates by an amount to reflect actual costs incurred in the test year just as it disallowed ENMAX's request for increases to the going-in rates to reflect higher actual costs.[88]

3.3.2 Company proposals

3.3.2.1 Proposals to move from mid-year to end-of-year for rate base purposes

97. ATCO Electric requested an adjustment to its 2012 distribution rates to move from a mid-year calculation of rate base to an end-of-year calculation of rate base to reflect the full impact of its 2012 capital investment.[89] ATCO Electric submitted that the Commission has approved the full amount of the costs relating to its 2012 capital investment, totalling $367 million, in the company's revenue requirement in its 2011 to 2012 General Tariff Application.[90] ATCO Electric's mid-year rate base was $1.392 billion compared to its end-of-year rate base of $1.508 billion. The capital related costs include financing costs, income tax, and depreciation.[91] Based on the evidence of Dr. Carpenter, ATCO Electric submitted that NERA's TFP study to be used for calculating X does not compensate ATCO Electric for the full year impact of

83 Exhibit 634.01, UCA argument, page 72.
84 Exhibit 300.02, UCA evidence of Russ Bell, pages 87 to 89.
85 Exhibit 642.01, IPCAA reply argument, paragraph 62 and Exhibit 636.01, CCA argument, paragraph 375.
86 Exhibit 646.02, EPCOR reply argument, paragraph 302.
87 Exhibit 647.01, ATCO Electric reply argument, paragraph 246 and Exhibit 648.02, ATCO Gas reply argument, paragraph 518.
88 Decision 2009-035, paragraph 83.
89 Exhibit 98.02, ATCO Electric application, paragraphs 215 to 220.
90 Exhibit 98.02, ATCO Electric application, paragraphs 215 and 216 and Decision 2011-134.
91 Exhibit 98.02, ATCO Electric application, paragraphs 217 and 218.

2012 additions that were not incorporated in the 2012 rates. Dr. Carpenter's evidence purported to show that NERA's study is based on a rate base growth of peer group utilities of 4.5 per cent and the company had an approximate rate base growth of 17 per cent in 2012.[92]

98. ATCO Gas also proposed to use end-of-year values rather than applying the mid-year convention for its rate base calculations in order to reflect the full impact of its 2012 capital investments.[93] ATCO Gas submitted that the mid-year convention is used in order to recognize that not all investments occur on the first day of January. In employing the mid-year convention, the revenue requirement is adjusted to reflect the full year costs including depreciation, income tax, and carrying costs for the prior year's investment[94] but an adjustment for capital investments is required to fully recognize the investments in going-in rates.

99. Interveners disagreed with the proposal to use end-of-year investment values to determine rate base. Calgary stated that the effect of moving from the mid-year convention to the end-of-year is to increase the baseline revenue requirement. Calgary argued that, "AG's approach has the effect of increasing the baseline revenue requirement – the starting point for the revenue trajectory – over and above the point at which the Commission has already deemed reasonable from the approved revenue requirement."[95] It would also be inconsistent with its proposed use of average number of customers in ATCO Gas's PBR formula.[96]

100. The CCA supported Calgary's position and argued that ATCO Gas' request should not be approved.[97]

Commission findings

101. The mid-year rate base convention is the accepted method for approximating the cost of capital investments in the year, and for the purposes of calculating other capital related costs. The mid-year convention uses an arithmetical average of a utility's investments to account for capital related costs uniformly over the entire year, recognizing that assets are added to rate base throughout the year. It is commonly used in regulatory jurisdictions in North America.

102. Had a cost of service rate application been filed for 2013, it would have accounted for 2012 capital expenditures in opening plant balances for rate base and an entire year's operating expenses for the use of those assets. However, 2013 capital expenditures would still be subject to the mid-year convention. In its December 16, 2010 letter, the Commission determined that the forthcoming rate decisions for the 2012 test year will be used to establish the going-in rates for the companies. Therefore, PBR will take these going-in rates and will in effect apply the I-X mechanism to the mid-year rate base. Carrying forward the mid-year forecast balance of rate base in the 2012 rates into the going-in rates continues to reflect the fact that new capital assets are put into service throughout the year. The Commission finds that the introduction of PBR does not require a departure from the use of the mid-year convention. No evidence was provided that other regulators employ this practice in adopting a PBR plan.

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92 Exhibit 476.01, ATCO Electric rebuttal evidence, paragraph 76.
93 Exhibit 99.01, ATCO Gas application, page 45-46.
94 Exhibit 99.01, ATCO Gas application, paragraph 132.
95 Exhibit 298.02, Calgary evidence, page 49, paragraph 176.
96 Exhibit 629.01, Calgary argument, page 69.
97 Exhibit 636.01, CCA argument, paragraphs 230 and 231.

103. The Commission finds no compelling reason to depart from the use of the mid-year convention. Accordingly, the Commission denies ATCO Electric's and ATCO Gas' proposal to use 2012 end-of-year forecast values rather than applying the mid-year convention for the rate base calculations included in going-in rates.

3.4 Individual adjustments to going-in rates requested by the companies

3.4.1 Fortis

104. Fortis proposed to update its 2013 opening values to reflect 2012 actual capital expenditures and related effects.[98] Fortis also proposed two adjustments to account for the full cost of a distribution control centre and one for depreciation rates.

105. At the hearing, Fortis requested a one-time adjustment to going-in rates to reflect the full cost of a distribution control center.[99] This adjustment was required because the timing of the distribution control centre implementation changed and now falls between 2012 and 2013.

106. With respect to the depreciation rates, Fortis proposed an adjustment to the depreciation rates established in its negotiated settlement. The negotiated settlement was signed on November 7, 2011 and approved by the Commission on April 18, 2012 in Decision 2012-108.[100] Fortis argued that "going-in rates for depreciation costs alone are fine on a going in basis" but due to Fortis' PBR assumptions the going-in rates should recognize "$60 million more of rate base compared to the plan assumptions when we set our PBR proposal."[101]

3.4.2 ATCO Electric

107. ATCO Electric requested two adjustments: one to include the final 2012 costs for three buildings and an adjustment for capitalized pension costs.

108. ATCO Electric proposed adjustments to its 2012 distribution rates to recognize full forecast costs and property taxes for three buildings with in-service dates falling in the second half of 2012.[102] The three buildings are located in Grande Prairie, Lloydminster, and Stettler.

109. ATCO Electric also proposed an adjustment to remove the cash basis current year recovery of its capitalized pension costs from going-in rates.[103] ATCO Gas removed the cash basis current year recovery of capitalized pension costs in its 2011 to 2012 general rate application[104] and ATCO Electric sought a similar change to ensure distribution pension costs were treated in the same manner by both ATCO companies. ATCO Electric therefore is no longer seeking cash basis current year recovery of capitalized pension costs.[105] Consequently, an

98 Exhibit 100.02, Fortis application, paragraph 42.
99 Exhibit 633, Fortis argument, page 122.
100 Decision 2012-108: FortisAlberta Inc, Application for Approval of a Negotiated Settlement Agreement in respect of 2012 Phase I Distribution Tariff Application, Application No. 1607159, Proceeding ID No. 1147, April 18, 2012.
101 Testimony of Mr. Lorimer, Transcript, Volume 11, pages 2184-2188 as quoted in Fortis argument, Exhibit 633.01, pages 121-122.
102 Exhibit 98.02, ATCO Electric application, paragraphs 210-214.
103 Exhibit 98.02, ATCO Electric application. paragraphs 221 and 222.
104 Decision 2011-450 ATCO Gas (A Division of ATCO Gas and Pipelines Ltd.) 2011-2012 General Rate Application Phase I, Application No, 1606822, Proceeding ID. No, December 5, 2011, paragraph 5, Table 2 shows capital pension – removal of immediate collection: costs of $13,257,000 were removed for 2012.
105 Exhibit 98.02, ATCO Electric application, paragraphs 221 and 222.

adjustment to going-in rates is required to reflect the change in recovery of these costs. In Application No. 1608750 (Proceeding ID No. 2078, the ATCO Utilities Compliance with Decision 2012-166[106]) filed on August 15, 2012, the Commission has been requested to determine the adjustment required to reflect the removal of the cash basis current year recovery of capitalized pension costs from the 2012 revenue requirement for ATCO Electric. ATCO Electric stated that the adjustment of capitalized pension costs was not commented on by interveners and it should be approved.[107]

3.4.3 ATCO Gas

110. ATCO Gas proposed an adjustment to going-in rates to account for the actual 2011 to 2012 urban mains replacement (UMR) capital expenditures in excess of the forecasts approved in Decision 2011-450.[108] ATCO Gas requested the opportunity to file a future application for an adjustment to its 2012 going-in revenue requirement for its actual 2011 to 2012 UMR expenditures. ATCO Gas submitted this approach is consistent with the mid-year convention and the effect on 2012 capital investment is consistent with what would occur under a cost of service rates application had one been filed to set rates for 2013.[109] ATCO Gas stated:

> The findings of the Commission on this matter are similar to the findings of the AEUB in Decision 2003-072, where the Board held ATCO Gas' UMR expenditures at approximately $7 million per year for the years 2003 and 2004.1 In the 2005 –2007 GRA, ATCO Gas was able to support the prudence of the actual UMR projects undertaken in 2003 and 2004, at a total cost of approximately $22 million, rather than the $14 million that had been approved.[110]

111. ATCO Gas stated that "[i]t is not reasonable to expect ATCO Gas to carry the cost of these prudent investments over the full term of its PBR Plan."[111] It further stated with respect to the ability to recover these UMR costs: "[t]o not provide ATCO Gas with this ability increases the risk to the utility, and it prevents ATCO Gas from having a reasonable opportunity to recover its prudently incurred costs, including a fair return."[112]

3.4.4 AltaGas

112. AltaGas proposed four adjustments to going-in rates: annualization of costs associated with monthly meter reading, income tax timing differences between 2012 and 2013, including losses carried forward, impacts of changes in pension expense from 2012 to 2013, and recovery of 2013 Natural Gas System Settlement Code (NGSSC) capital forecasts and annualization of capital and O&M expenses related to NGSSC costs.[113] AltaGas stated that its proposed annualized adjustments for metering and NGSSC costs are required in order for it to earn a fair return.[114]

106 Decision 2012-166: ATCO Utilities (ATCO Gas, ATCO Pipelines and ATCO Electric Ltd.), 2011 Pension Common Matters Compliance Filing, Application No. 1607949, Proceeding ID No. 1599, June 14, 2012.
107 Exhibit 631.01, ATCO Electric argument, paragraph 318.
108 Exhibit 389.01, ATCO Gas update, page 5 and 6.
109 Exhibit 389.01, ATCO Gas application update, paragraph 8.
110 Exhibit 389.01, ATCO Gas update, page 2, paragraph 4.
111 Exhibit 389.01, ATCO Gas update, page 3, paragraph 5.
112 Exhibit 389.01, ATCO Gas update, page 4, paragraph 7.
113 Exhibit 628.01, AltaGas argument, pages 80 and 81.
114 Exhibit 628.01, AltaGas argument, paragraph 273.

113. AltaGas proposed its 2012 distribution rates be adjusted to reflect changes in income taxes and depreciation.[115] The adjustment for income taxes is intended to recognize changes in income tax timing differences between 2012 and 2013, including losses carried forward.[116] AltaGas has requested an adjustment to account for a forecast change from 2012 to 2013 related to income taxes. This adjustment would be for book to tax timing differences.[117] In the hearing, AltaGas was asked about its proposal to adjust taxes to reflect a reduced level of capital cost allowance. The AltaGas witness responded:

> Well, our proposal is that the going-in rates be adjusted to allow for the increase in the income taxes, the cash income tax, expense the company will be incurring as a result of the -- of its ability to claim an equivalent CCA amount as it had in 2012. In other words, in 2012 because AUI was able to claim maximum CCA at the direction of the Commission, it effectively reduces its cash taxes to zero. So there is in fact zero dollars for income taxes sitting in the revenue requirement, which would drive the going-in rates. So we're simply asking that the company be allowed to have a component for income taxes in its going-in rates, which would be the equivalent of what it would require under normal circumstances.[118]

114. AltaGas also proposed an adjustment for the impact of changes in pension expenses from 2012 to 2013.[119] On April 18, 2012, AltaGas provided corrections and updates to its application.[120] AltaGas stated, with respect to meter reading that, due to the timing of Decision 2012-091, AltaGas "will not be able to commence the additional readings until July 1, 2012. As AltaGas' intention is to adjust its 2012 revenue requirement in its compliance filing to reflect only a half year of the additional costs, it will be necessary to make an adjustment to going-in rates to reflect the full year of costs."[121] AltaGas also asked to reserve the right to apply for a going-in adjustment for the NGSSC capital cost forecast for adjustments not included in its 2012 compliance filing.[122]

Commission findings

115. The Commission considers that each of the individual adjustments to going-in rates except for the those items specifically referred to below are requests to adjust approved 2012 revenue requirements for after-the-fact events or circumstances and are therefore denied. The Commission has confirmed the position taken in Decision 2009-035 that it will not accept adjustments to the going-in rates to account for 2012 actual results. As noted in that decision: "[a]djustments to account for actual results should not be made selectively but, rather, should only be made in the context of a full rate case which would consider the forecast costs for a subsequent time period."[123]

116. However, the Commission will allow the ATCO Electric requested adjustment to going-in rates to remove its cash basis current year recovery of capitalized pension costs. In

115 Exhibit 110.01, AltaGas application, page 12, paragraph 44.
116 Exhibit 628.02, AltaGas argument, page 80.
117 Exhibit 110.01, AltaGas application, paragraph 44.
118 Transcript, Volume 9, page 1610, lines 10 to 23, AltaGas witness Mr. Mantei in response to cross-examination by CCA counsel.
119 Exhibit 628.01, AltaGas argument, pages 80-81.
120 Exhibit 529, AltaGas corrections and amendments to AltaGas' application.
121 Exhibit 529, AltaGas corrections and amendments to AltaGas' application, pages 4 and 5.
122 Exhibit 529, AltaGas corrections and amendments to AltaGas' application, pages 4 and 5.
123 Decision 2009-035, paragraph 74.

Decision 2012-166[124] the Commission approved the request of the ATCO Utilities to no longer collect the capital component of pension costs in the current year on a cash basis and to fund it as part of each utility's invested capital.[125] Given this decision and ATCO Gas' removal of similar costs in its general rate application, the Commission considers that this adjustment provides for consistent treatment between the ATCO distribution companies for the purpose of setting going-in rates for PBR. The requested adjustment is similar in nature to the adjustment to going-in rates permitted in Decision 2009-035 for the inclusion of ENMAX short term incentive plan costs. It is also similar to the replacement of a placeholder, and is not a rate adjustment made after-the-fact to reflect actual results. The Commission grants ATCO Electric's removal of its cash basis current year recovery of capitalized pension costs for the purposes of establishing going-in rates. The necessary adjustment to 2012 revenue requirement will be determined by the Commission in Proceeding ID. 2078. With respect to AltaGas' NGSSC costs for 2012, the Commission determined in Decision 2012-091, that the evaluation of AltaGas' 2012 forecast costs for NGSSC will be determined in AltaGas' compliance filing to its general rate application.[126] The Commission's decision on AltaGas' compliance filing to its general rate application will establish the final rates for 2012. These rates will form the basis for the going-in rates for PBR and, as a result, recovery of NGSSC costs in 2013 are already accounted for, adjusted by I-X. Accordingly, there is no need for an adjustment for NGSSC costs in AltaGas' going-in rates. With respect to AltaGas' request for a going-in rates adjustment for tax timing differences, the Commission has addressed this issue in Section 7.4.2.3.5 by indicating that book-to-tax timing differences should be the subject of a Y factor application.

3.5 Other adjustments to going-in rates

117. Certain parties to this proceeding requested removal of all deferral accounts and other Y factor adjustments from their 2012 revenue requirements. For instance, ATCO Gas requested removing the amounts included 2012 approved revenue requirement corresponding to deferral accounts treated as Y factor adjustments under PBR.[127]

Commission findings

118. The removal from going-in rates of amounts corresponding to approved Y factor items from going-in rates is discussed in Section 7.4.4 of this decision.

124 Decision 2012-166: ATCO Utilities (ATCO Gas, ATCO Pipelines and ATCO Electric Ltd.) 2011 Pension Common Matters Compliance Filing, Application No. 1607949, Proceeding ID No. 1599, June 14, 2012.

125 Decision 2012-166, paragraph 70.

126 AltaGas Utilities Inc. Compliance Filing Proceeding ID No. 1921 and Decision 2012-091, AltaGas Utilities Inc, 2010 to 2012 General Rate Application – Phase I, Application No. 1606694, Proceeding ID No. 904, April 9, 2012.

127 Exhibit 99.01, ATCO Gas application paragraph 135 and Exhibit 632.01, ATCO Gas argument, paragraph 330.

4 Price cap or revenue cap

119. The electric distribution companies (ATCO Electric, EPCOR and Fortis) proposed that their PBR (performance-based regulation) plans take the form of a price cap. Under a price cap plan, a company is allowed to change its customer rates according to an indexing formula that is typically comprised of an inflation measure, known as the I factor, and a productivity offset, commonly referred to as the X factor. An illustrative generic formula describing a typical price cap plan can be written as follows:

For each customer class:

$$\mathbf{Rates_t = Rates_{t-1} * (1 + I - X) \pm Other\ Adjustments}$$

120. As the formula above illustrates, the current year's customer rates for each class are derived by adjusting the previous year's rates by a percentage equal to the difference between the relevant I and X factors (as well as any other allowed or mandated adjustments discussed in other sections of this decision).

121. A price cap plan establishes annual customer rates regardless of the amount of energy transported through a company's system. Accordingly, under price cap plans the company ordinarily bears the risk of a change in energy volumes transported through its system. An increase in the amount of energy transported would lead to an increase in the company's revenues, and a decrease in the amount of energy transported would lead to a decrease in the company's revenues. As a result, parties to this proceeding pointed out that the use of price caps can be problematic when there is expected to be a continuing decline in sales per customer.

122. ATCO Gas and AltaGas both presented evidence that average gas deliveries per customer had been declining for most customer classes in Alberta and for several years and were expected to continue to decline. The average decline rate for ATCO Gas and AltaGas was approximately 1.5 per cent per year.[128] No party took issue with this evidence. Dr. Lowry, on behalf of the CCA, also confirmed that declines in average use by small-volume customers have been common in the gas distribution industry for many years. Contributing factors include demand side management (DSM) programs, general improvements in the technology of furnaces and other gas-fired equipment, and changes in building codes and appliance efficiency standards.[129] None of the electric distribution companies indicated a similar trend in declining use per customer.[130]

123. Because the rates charged by ATCO Gas and AltaGas are composed of fixed and variable components, a significant portion of revenue for both companies is determined by actual deliveries. The gas distribution companies submitted that a price cap plan would result in chronic revenue shortfalls in an environment of declining deliveries per customer.[131] To address this issue, both gas distributors, ATCO Gas and AltaGas, proposed that their PBR plans take form of a revenue-per-customer cap.

124. A revenue-per-customer cap is similar to the price cap plans discussed above. However, instead of limiting the change in customer rates from one year to the next, it limits the change in

128 Transcript, Volume 3, page 553, lines 18-22 and Exhibit 212.02, AUC-ATCOGas-1(c) and (d); Transcript, Volume 8, pages 1356-1357 and Exhibit 248.03, AUC-AltaGas-8(c) and (e).
129 Exhibit 307.01, PEG evidence, page 17.
130 Transcript, Volume 3, pages 557-559; Exhibit 103.05, Cicchetti evidence, page 14.
131 Exhibit 632, ATCO Gas argument, paragraph 141 and Exhibit 628, AltaGas argument, page 35.

a company's revenue per customer on a class by class basis, as illustrated by the following general formula:

For each customer class:

$$\textbf{Revenue per customer}_t = \textbf{Revenue per customer}_{t-1} * (1 + I - X) \pm \textbf{Other Adjustments}$$

125. Under a revenue-per-customer cap plan, the approved revenue per customer from the previous year is adjusted by the I-X index on a class by class basis to arrive at the upcoming year's revenue-per-customer cap. However, to calculate actual customer rates, the indexed revenue must be divided by the forecast consumption per customer on a class by class basis. Consequently, unlike in a price cap plan, forecast billing determinants represent an integral part of the revenue cap mechanism, regardless of any other adjustments outside of the I-X indexing mechanism.

126. Both gas distribution companies indicated that a revenue cap plan is common for natural gas distribution companies in Canada because it allows the company to update its billing determinants and adjust its rates to account for the effect of the declining use per customer that is common to the natural gas industry.[132] ATCO Gas highlighted the fact that PBR plans in the form of revenue cap plans were previously approved by the regulators for other Canadian gas distribution companies, including Enbridge Gas, Gaz Métro and Terasen Gas.[133]

127. As AltaGas explained in its evidence, PBR plans designed in the form of price caps are not consistent with the underlying cost structure of gas distribution companies. AltaGas pointed out that the total cost of gas distribution largely depends on the capacity required to provide for maximum daily throughput (peak loads) and transport distances (or the length of distribution line), and is largely unrelated to total energy use. However, these predominately fixed costs are mostly recovered through variable charges, for example dollars per gigajoule delivered. As a result, while changes in use per customer have virtually no impact on cost, they have a direct impact on the company's total revenues.[134]

128. This effect is further amplified by the economies of density[135] in the gas distribution industry, with the result that the price charged for an additional unit of gas delivered to customers is typically above the marginal cost of delivery. In such circumstances, increases in use per customer will increase revenue more rapidly than costs and, conversely, decreases in use per customer will decrease revenue more rapidly than costs. Consequently, unexpected changes in use per customer may lead to "windfall profits or extraordinary losses."[136] More importantly in the context of Alberta gas distribution companies, when use per customer is expected to decline on a continuing basis, the revenue decline will be fairly certain. By focusing on revenue per customer as opposed to the price per unit of gas delivered, the revenue cap approach to PBR is designed to account for the revenue decline associated with declining use per customer.

[132] Exhibit 99.01, ATCO Gas application, paragraph 19 and Transcript, Volume 8, page 1364, lines 18-20.

[133] Transcript, Volume 3, page 551, line 2 to page 552, line 2.

[134] Exhibit 477.01, AltaGas rebuttal evidence, paragraph 18.

[135] As AltaGas explained in its evidence, economies of density exist when an increase in usage to a customer on the network leads to a less than proportional increase in total costs. In gas distribution, costs are primarily related to connecting a customer to the network and are not related to the customer's use, leading to economies of density. (Exhibit 110.01, footnote 1 on page 2).

[136] Exhibit 110.01, Christensen Associates evidence, paragraph 7.

129. The CCA stated that revenue caps sidestep the need for the very low X factors that would otherwise be needed to provide compensatory rate escalation in the circumstances where average use by small-volume customers has a markedly downward trend.[137] This view was shared by Calgary.[138]

130. With respect to the incentive properties of the proposed PBR plans, parties to this proceeding agreed that both price cap and revenue cap formulas create similar incentives to minimize costs.[139] In fact, both gas companies pointed out that they would be indifferent as between a price cap plan and a revenue cap plan if there were a deferral account or some other revenue adjustment mechanism to account for changes in use per customer under the price cap plan. However, neither company favoured the use of a price cap plan with the adjustment mechanism due to the increased complexity and administrative burden of such approach as compared to the proposed revenue-per-customer cap plans.[140]

131. At the same time, NERA pointed out that price caps and revenue caps differ with regard to their potential impact on sales (either in total or on a per-customer basis) and in the incentive to maintain quality. NERA explained that a firm under a price cap plan has an incentive to increase sales if its additional revenues from new sales exceed its incremental costs. Firms under a revenue cap plan do not have such an incentive. Additionally, NERA noted that service quality can be more of a concern under revenue caps than price caps because, under a revenue cap, if poor service quality leads to fewer sales, the lost revenue can be made up through the price increases for remaining customers that arise from application of the formula.[141]

132. Parties also observed that a revenue-per-customer cap plan would diminish the disincentive a company has to promote the DSM measures. AltaGas noted that, because the price it charges for the delivery of gas is typically greater than the marginal cost for the service, any reduction in gas consumption will have a greater impact on revenues than costs. Thus, under a price cap plan, it is in the financial interest of the company to limit the reduction in customer use and, instead, encourage increased consumption, if possible.[142] The CCA experts reached a similar conclusion and pointed out that revenue cap plans mitigate the disincentive to promote DSM plans by weakening the link between changes in system use (e.g., energy deliveries and peak demand) and changes in earnings.[143] However, Ms. Frayer on behalf of Fortis pointed out that revenue caps may create distorted incentives for companies to act like monopolists, raising prices while reducing output in order to maximize profit margins, giving rise to the so-called “Crew-Kleindorfer effect.”[144]

133. AltaGas submitted that, unlike a revenue cap formula that applies to a firm’s overall revenue, the proposed revenue-per-customer cap approach provides an incentive to continue connecting new customers because customer growth drives revenue growth. In contrast, a straight revenue cap formula would not provide such an incentive because under a revenue cap

137 Exhibit 307.01, PEG evidence, page 16.
138 Transcript, Volume 15, page 2926, lines 23-35 and page 2927, lines 1-11.
139 Exhibit 195.01, AUC-NERA-13; Exhibit 628, AltaGas argument, page 35; Exhibit 629, Calgary argument, page 37.
140 Exhibit 632.01, ATCO Gas argument, page 44 and Exhibit 628.01, AltaGas argument, page 35.
141 Exhibit 195.01, AUC-NERA-13.
142 Exhibit 110.01, Christensen Associates evidence, paragraph 8.
143 Exhibit 307.01, PEG evidence, page 16.
144 Exhibit 100.02, Frayer evidence, page 23.

approach the company can raise prices to meet the revenue cap without having to connect new customers.[145]

134. Finally, ATCO Gas and AltaGas pointed out that their respective revenue-per-customer cap plans do not contemplate an adjustment if the forecast PBR revenue or consumption per customer deviates from the actual values. However, the two PBR plans differ with regard to their treatment of forecast customer growth. ATCO Gas proposed that the forecast of the average number of customers be reconciled with the actual number of customers when it becomes available, while AltaGas' plan does not provide for such a true-up.[146]

Commission findings

135. A price cap plan sets customer rates in accordance with the established I-X index, regardless of the company's actual costs and the amount of energy transported. A revenue cap also employs an I-X index. However, under the latter approach, it is the revenue of the company and not its rates that is adjusted by the I-X index. Consequently, customer rates may fluctuate so long as revenue does not exceed the revenue cap.

136. The PBR plans proposed by ATCO Gas and AltaGas demonstrate that under a revenue-per-customer cap plan, customer rates are calculated on a class by class basis by dividing the revenue-per-customer cap derived from the formula by the forecast use per customer for the upcoming year. For example, if the actual billing determinants from the previous year were used for calculating customer rates in the upcoming year, the declining use per customer would lead to a systematic under-recovery of revenues by the companies. Under the proposed revenue-per-customer cap plans, customer rates will go down if the company forecasts an increase in energy consumption per customer in the upcoming year. Likewise, customer rates will go up if a decrease in energy consumption per customer is projected for the coming year. In either case, a company's revenue per customer will not exceed the value established by the PBR formula.

137. Under a price cap plan, the company ordinarily bears the risk of changes in energy volumes delivered, while under a revenue cap plan the company is largely protected from volumetric risk. Parties to this proceeding pointed out that the volumetric risk may become too great to bear when there is an expected continuing decline in use per customer.[147] In this circumstance, the use of a price cap may be problematic as it may expose the company to significant reductions in revenues resulting from declines in use per customer.

138. Both ATCO Gas and AltaGas indicated that, despite the overall sales growth, they are experiencing a continuing decline in use per customer, averaging approximately 1.5 per cent per year.[148] This rate of decline in average customer use is forecast to continue into the future. Furthermore, the companies noted that overall customer growth and increased consumption by some existing customers does not completely offset overall declines in the average use per customer.[149] The Commission accepts the average usage per customer decline rates forecasted by ATCO Gas and AltaGas and accepts the position that a price cap plan would result in significant

145 Exhibit 243.01, AUI-CCA-2(g) and (h).

146 Exhibit 99.01, ATCO Gas application, paragraphs 43-44; Transcript, Volume 8, page 1370, line 25 to page 1371, line 6 (AltaGas).

147 Exhibit 632, ATCO Gas argument, paragraphs 141-143 and Exhibit 628, AltaGas argument, page 35.

148 Transcript, Volume 3, page 553, lines 18-22 and Exhibit 212.02, AUC-ATCOGas-1(c) and (d); Transcript, Volume 8, pages 1356-1357 and Exhibit 248.03, AUC-AltaGas-8(c) and (e).

149 Transcript, Volume 3, page 554, lines 12-15 and Volume 8, page 1356, lines 2-9.

revenue reductions under existing rate structures due to declining gas usage if such declines in revenue were not otherwise adjusted for.

139. The Commission also agrees with AltaGas' argument that the revenue-per-customer cap approach to PBR is consistent with the underlying cost structure of gas distribution utilities. A large proportion of gas distributors' costs are fixed, while a significant amount of these costs is recovered through variable charges. As a result, unexpected changes in use per customer may lead to significant variations in the revenues of gas distribution companies that are not offset by cost changes. By focusing on revenue per customer as opposed to price per unit of gas delivered, the revenue-per-customer cap PBR plans proposed by ATCO Gas and AltaGas account for the impact of changes in use per customer on the companies' revenues.

140. Given the above, the Commission considers that forecasting use per customer for the upcoming year is warranted in this case since it accounts for the declining use per customer.

141. The Commission agrees with the parties to this proceeding that the incentive properties of both price cap and revenue-per-customer cap plans are largely the same. Both types of plans rely on an I-X indexing mechanism that decouples revenues from the costs of service, thus creating efficiency incentives. Additionally, both price cap and revenue-per-customer cap formulas use customer growth as a driver for revenue growth, thus providing incentives to continue connecting new customers. The Commission also acknowledges that, by making companies indifferent to volume changes, revenue-per-customer caps provide incentives to promote DSM plans.[150]

142. The Commission also accepts NERA's proposition that diminished service quality can be more of a concern under revenue caps than price caps. However, the Commission considers that concerns with respect to the maintenance of service quality can be addressed through service quality monitoring and reporting measures under both price cap and revenue cap PBR plans. Service quality is discussed in Section 14 of this decision.

143. Overall, the Commission agrees with ATCO Gas and AltaGas that the revenue-per-customer cap approach to PBR adequately addresses the issues associated with declining usage per customer without decreasing the intended efficiency incentives of performance-based regulation. The Commission observes that Calgary and the CCA supported the use of revenue-per-customer cap plans for ATCO Gas and AltaGas.[151]

144. Regarding the issue of a true-up to the actual number of customers, as proposed by ATCO Gas, the Commission notes that the focus of the PBR plans proposed by the gas distribution companies in this proceeding is on indexing the revenue per customer for each customer class, not the overall revenue of a company. Accordingly, the correct measure to true up, if any, is the forecast use per customer.

[150] The commission has denied certain types of demand side management programs proposed by the gas distribution companies as being inconsistent with the legislative framework. For example see, Decision 2011-450: ATCO Gas (A Division of ATCO Gas and Pipelines Ltd.), 2011-2012 General Rate Application Phase I, Application No. 1606822, Proceeding ID No. 969, December 5, 2011, paragraph 683 and Decision 2012-091: AltaGas Utilities Inc., 2010-2012 General Rate Application Phase I, Application No. 1606694, Proceeding ID No. 904, April 9, 2012, paragraph 625.

[151] Exhibit 329, Calgary argument, page 37; Exhibit 636, CCA argument, page 2 and Transcript, Volume 13, page 2534, lines 13-17 (Lowry).

145. In the interest of regulatory efficiency, the Commission considers that no true up for the actual weather normalized use per customer is required. The Commission directs the gas companies to use the actual average change in weather normalized use per customer (per class) for the preceding three years as their forecast percentage change in weather normalized use per customer for the upcoming year. This percentage change is to be applied to weather normalized use per customer (actual and projected per class) for the current year to determine the forecast for the upcoming year. The Commission is satisfied that the rate of change in weather normalized use per customer over the preceding three year period will result in a reasonable forecast of weather normalized use per customer for the upcoming year.

146. With respect to the PBR plans of ATCO Electric, EPCOR and Fortis, these companies indicated that a declining use per customer or other types of volumetric risk are not an issue for them.[152] As well, Dr. Lowry pointed out that North American electric utilities often experience modest growth in average use by small volume customers when large DSM programs are not underway in their service territories.[153] Consequently, the Commission has no concerns with the use of a price cap approach in the PBR plans for the electric distribution companies.

5 I factor

5.1 Characteristics of an I factor

147. The inflation factor, also referred to as an I factor or an input price index, is the component of a price cap or revenue cap PBR (performance-based regulation) plan that reflects the expected changes in the prices of inputs that the companies use. As the companies' experts explained, a PBR formula should be designed to produce rates that reflect inflationary pressures on input prices that a company is expected to experience from year to year during the term of the plan.[154] The purpose of the inflation factor is to pass on to customers the increases in the costs of goods and services purchased by the company (for example, cost of the materials and supplies, salaries of the company's staff, etc.) that are driven by macro-economic forces and are beyond the control of the company's management.[155]

148. The UCA noted that, by setting an automatic adjustment for the company's cost changes, an input price index obviates the need to hold frequent cost of service proceedings. The UCA pointed out that, in effect, the I factor mirrors the process of reviewing a company's costs and adjusting rates on a prudency basis, in effect using the selected inflation measure as a prudency test.[156]

149. In their respective PBR submissions, parties outlined a number of considerations for choosing the relevant I factor. Specifically, parties proposed the following selection criteria for establishing an inflation index:[157]

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152 Transcript, Volume 3, pages 557-559; Exhibit 103.05, Cicchetti evidence, page 14.
153 Exhibit 307.01, PEG evidence, page 17.
154 Exhibit 110.01, Christensen Associates evidence, paragraph 29; Exhibit 98.02, Carpenter evidence, page 15.
155 Exhibit 100.02, prepared testimony of Julia Frayer, page 33.
156 Exhibit 299.02, Cronin and Motluk UCA evidence, page 182, A87.
157 Exhibit 631.01, ATCO Electric argument, paragraph 38; Exhibit 632.01, ATCO Gas argument, paragraph 34; Exhibit 628.01, AltaGas argument, pages 11-12; Exhibit 633.01, Fortis argument, paragraph 63; Exhibit 636.01, CCA argument, paragraph 48.

- The I factor must be indicative of the change in input prices that the company expects to experience over the term of the PBR plan.
- The inflation index must be published by a reputable, independent agency and made readily available on at least an annual basis.
- The I factor should be transparent, simple to calculate and easy to understand.
- The selected I factor should not be overly volatile.
- The I factor should reflect a broad measure of inflation rather than the experience of the specific company to which the PBR plan is to apply, so that the company cannot significantly affect the index.

150. In addition to these criteria, Dr. Ryan on behalf of EPCOR indicated that, in conducting his analysis and recommending an inflation index, he considered the Commission's findings in Decision 2009-035. In particular, EPCOR's expert recommended using an input-based index, thus avoiding the need for making adjustments to the productivity factor, which would be the case if an output-based price index were used.[158] This recommendation was also supported by the UCA.[159]

151. Additionally, in setting out his proposed criteria, Dr. Ryan recommended that if the inflation factor was composed of different component indexes, the weighting of these should be fixed rather than vary year to year, so that the company's incentives are not influenced by relative rates of inflation in the component indexes.[160]

152. The CCA pointed out that the I factor selection criteria are often in conflict and that there is "considerable art in developing an index that sensibly balances simplicity and accuracy."[161]

Commission findings

153. The I factor provides a mechanism to adjust the companies' prices[162] (in the case of a price cap plan) or revenues (in the case of a revenue-per-customer cap plan) year over year to reflect changes in the prices of inputs that the companies use.

154. As the ATCO companies pointed out in their arguments, a PBR plan should provide incentives for the company to undertake efficiency improvements to manage and minimize the costs that are within its control. However, changes in a company's input prices due to inflation are not within its ability to control, although the company may be able to use those inputs more efficiently than its competitors.[163] In competitive markets, when faced with a universal, economy-wide increase in input prices (such as an increase in salaries and wages, higher fuel prices, etc.), companies are often left with no choice but to pass on these higher costs to consumers. Similarly, when the prices of inputs go down, competition in the market forces the companies to lower their prices. The I factor in the PBR plans is intended to mimic this characteristic of competitive markets.

[158] Exhibit 103.04, Dr. Ryan evidence, paragraph 8.
[159] Exhibit 634.02, UCA argument, paragraph 76.
[160] Exhibit 103.04, Dr. Ryan evidence, paragraph 8.
[161] Exhibit 636, CCA argument, paragraph 49.
[162] Utility output prices are most commonly referred to as rates. In the context of a price cap plan they are referred to as prices.
[163] Exhibit 631, ATCO Electric argument, paragraph 37.

155. All parties agreed that the selected I factor should be indicative of the change in input prices that the companies are expected to experience, be transparent, simple to calculate and easy to understand. In addition, parties recommended that the inflation factor should not be overly volatile, must be published on a regular basis by a reputable independent agency and should not be overly influenced by the company itself. The Commission agrees.

156. The choice between input and output inflation indexes, the use of a single index or a composite I factor consisting of multiple indexes and the weights to be assigned to the elements of a composite I factor are discussed in the subsequent sections of this decision.

5.2 Selecting an I factor

5.2.1 The rationale behind a composite I factor

157. In Decision 2009-035, dealing with ENMAX's 2007-2016 FBR (formula-based ratemaking) application, the Commission approved a composite I factor that includes the distribution construction price index as measured by the Canadian Electric Utility Construction Price Index (EUCPI) and the Alberta Average Hourly Earnings (AHE) index with a 50:50 fixed weighting throughout the PBR term.[164]

158. The companies argued that, in general, no single measure of inflation can explain all the cost trends facing a utility, and they maintained that greater accuracy can be achieved by constructing a composite index composed of published indexes, weighted according to the average relationship among the company's various inputs.

159. Specifically, AltaGas' experts explained that a utility primarily purchases two types of inputs, employee time and goods and services from other firms. The prices that a company in Alberta must pay for these inputs will be affected primarily by economic conditions within the province of Alberta.[165] This position was supported by the other companies with each proposing that their respective I factors consist of two inflation indexes, one reflecting labour cost and the other reflecting the cost of non-labour items. Such a blended I factor would generally be calculated each year using the following weighted-average formula:

$$\textit{I factor} = w_l \ * \ \textit{Labour Price Index} + w_n \ * \ \textit{Other Costs Price Index}$$

160. For labour costs, the companies preferred to use either Average Hourly Earnings (AHE) or Average Weekly Earnings (AWE) for Alberta. For non-labour costs, the companies preferred to use either the EUCPI adjusted for Alberta inflation or the Alberta Consumer Price Index (CPI). These sub-indexes would be weighted based on the companies' historical proportions of labour (w_l) and non-labour (w_n) costs. The following table summarizes the proposed I factors as outlined in the electric distribution companies' respective PBR applications:

164 Decision 2009-035, paragraphs 144 and 149.
165 Exhibit 110.01, Christensen Associates evidence, paragraph 30.

Table 5-1 Summary of electric distribution companies' I factor proposals

	ENMAX[166] (distribution)	ATCO Electric (distribution)	Fortis	EPCOR (distribution)
Labour costs	Alberta AHE	Alberta AWE	Alberta AHE	Alberta AHE
Non-labour costs	EUCPI (no adjustment)	EUCPI (adjusted for Alberta)	EUCPI (adjusted for Alberta)	Alberta CPI
Weights (labour/non-labour)	50:50	65:35	61:39	80:20

161. Table 5-2 below presents the I factors proposed by the gas distribution companies in their respective PBR plans:

Table 5-2 Summary of gas distribution companies' I factor proposals

	ATCO Gas	AltaGas
Labour Costs	Alberta AWE	Alberta AWE
Other Costs	Alberta CPI	Alberta CPI
Weights (labour/non-labour)	57:43	57:43

162. The UCA supported the use of a composite I factor and indicated that the Commission should use the input price index approved for ENMAX in Decision 2009-035 for all the companies in this proceeding.[167]

163. The CCA also acknowledged the need for an inflation measure that reflects the "special inflationary conditions that sometimes occur in Alberta." The CCA pointed out that inflation can be much more rapid in Alberta than in Canada as a whole in some periods (for example, 2006 to 2008) and appreciably lower in other periods (2009 to 2010), since the province's economy can experience "booms and busts" because it is largely influenced by the production of price-volatile commodities.[168]

164. The CCA recommended that the I factor consist of either a single macroeconomic measure of Alberta price inflation or an appropriately designed custom index of Alberta utility input price inflation. With respect to macroeconomic inflation measures, the CCA recommended using either the Alberta gross domestic product implicit price index for final domestic demand (GDP-IPI-FDD) or the Alberta CPI.

165. PEG on behalf of the CCA, developed an index that tracks the prices of three categories of input costs: labour, materials and services, and capital. Specifically, PEG recommended using either CPI or GDP-IPI-FDD for Alberta as the proxy for the materials and supplies input price index and the Alberta AHE or AWE for the labour price index. For the capital cost category, PEG constructed this element as the product of a rate of return on capital (set initially at the weighted average cost of capital established for the subject utility in its most recent rate case)

[166] As approved in Decision 2009-035. ENMAX was included in this table for comparison purposes.
[167] Exhibit 634.02, UCA argument, paragraph 73.
[168] Exhibit 636, CCA argument, paragraph 44.

and a triangularized weighted average of past values of the EUCPI, with an adjustment to reflect Alberta construction market conditions.[169]

166. Calgary also recommended using the Alberta GDP-IPI-FDD index and indicated that it did not support the adoption of a composite I factor consisting of several weighted indexes because such an inflation measure would not be consistent with the simplicity principle.[170]

Commission findings

167. A number of parties pointed out that, because the Alberta economy is influenced by the production of price-volatile commodities such as oil and natural gas, it can experience wider swings in economic activity than the rest of the Canadian economy. As a result, inflation in the province can be quite different from inflation in the Canadian economy as a whole.

168. The companies also highlighted the fact that the presence of large scale capital-intensive oil and gas activity in Alberta leads to strong competition for labour resources, especially those involved in technical and engineering services, as well as capital-intensive projects. Accordingly, the companies were particularly concerned that the I factor be able to capture the effect of the tight labour market in Alberta.[171] As Dr. Cicchetti on behalf of EPCOR explained:

> But high oil prices and high gas prices, although those are now falling, but high oil prices at least have the effect of making the demand in the job market tighter, and the demand for people who are engineers of whatever kind who can be employed by electric distribution companies is tighter.[172]

169. The Commission agrees with these observations. Because of the relatively tight labour market in Alberta, salaries and wages have been rising faster than the national average during petroleum industry booms and have declined more rapidly or risen less quickly during economic slowdowns, as compared to the rest of Canada. Therefore, the Commission will include an Alberta-specific labour inflation component in the I factor of the companies' PBR plans to reflect labour inflation in the province.

170. The Commission agrees with the companies that all-encompassing macroeconomic inflation measures, such as Alberta GDP-IPI-FDD or Alberta CPI proposed by the CCA and Calgary, when used as the only measure of inflation, do not reflect the input price inflation faced by the companies. As ATCO Gas pointed out, using a single macroeconomic index for the I factor may result in a significant revenue shortfall due to the under-recovery of its labour-related costs.[173] Furthermore, the CCA agreed that both CPI and GDP-IPI-FDD in this context are output price indexes, thus requiring adjustments to the productivity measure (in this case a TFP (total factor productivity) study) in determining an X factor as explained in Section 6.4.1 below.[174] In the Commission's view, the need for such an adjustment more than offsets any simplicity and transparency benefits of using a single macroeconomic inflation measure.

169 Exhibit 307.01, PEG evidence, pages 52-54 and Exhibit 376.18, ATCO-CCA-63 attachment.
170 Exhibit 629.01, Calgary argument, page 22.
171 Transcript, Volume 7, page 1291, lines 13-16, Volume 11, page 2137, line 24 to page 2138, line 1.
172 Transcript, Volume 11, page 2061, lines 19-24.
173 Exhibit 632, ATCO Gas argument, paragraph 49.
174 Exhibit 636, CCA argument, paragraph 51.

171. Accordingly, for the reasons above the Commission finds that the use of a composite I factor in the PBR plans of Alberta utilities is warranted.

172. The Commission considers that the composite I factors proposed by the companies generally conform to the input price index selection criteria outlined in Section 5.1. The proposed sub-indexes for labour and non-labour costs are published by Statistics Canada on a regular basis and, as explained in further sections of this decision, do not require any subjective modifications. The Commission considers that these indexes are sufficiently broad-based to avoid potential concerns about the activities of the companies significantly influencing these measures.

173. In addition, as explained in Section 6.4.1 below, since all the components of the I factors proposed by the companies can be considered input price indexes for the Alberta electric and gas distribution companies, using such a composite I factor does not require an adjustment to TFP in determining an X factor in order to account for an input price differential and a productivity differential.

174. With respect to the customized index for labour, capital and materials proposed by the CCA, the Commission notes that a similar index was proposed by the UCA in the ENMAX FBR proceeding, as outlined in Decision 2009-035. In that decision, it was noted that this type of I factor was more data intensive and more complex than the Commission considered desirable for the purposes of a PBR plan.[175] Indeed, in this proceeding, the CCA pointed out that the selection of an inflation measure for a PBR plan is difficult because greater accuracy comes at the cost of greater complexity.[176] ATCO Gas pointed out that the CCA's index needed a 15 page spreadsheet with a number of significant, complex calculations.[177] During the hearing, Dr. Lowry concurred that the calculation of the proposed customized index would likely require a Ph.D.'s expertise.[178] As such, the Commission considers that the customized index proposed by the CCA suffers from the same data intensity and complexity drawbacks as did the UCA's proposal for ENMAX. Furthermore, similar to the proposed I factors of ATCO Gas and Fortis, the CCA's customized inflation factor involves a modification to EUCPI to attempt to better reflect Alberta inflation. The Commission discusses the shortcomings of such adjustments in Section 5.2.3 below.

175. Finally, the CCA contended that the added complexity of a customized inflation index was warranted because it better tracked input price inflation. However, when the CCA compared its proposed customized I factor to a GDP-IPI-FDD index, the results were within 0.01 percentage points of each other over the 2001 to 2010 period.[179]

176. In light of the above considerations, the Commission is not persuaded that the customized index proposed by the CCA is superior to the types of I factors proposed by the companies.

177. Similar to the findings in Decision 2009-035, the Commission recognizes that the blended I factors proposed by the companies do not specifically account for changes in the cost

[175] Decision 2009-035, paragraph 139.
[176] Exhibit 636, CCA argument, paragraph 49.
[177] Exhibit 472.02, ATCO Gas rebuttal evidence, paragraph 164.
[178] Transcript, Volume 13, page 2587, lines 1-6.
[179] Exhibit 372.01, AUC-CCA-20(c).

of capital.[180] Although there was some debate at the proceeding as to whether financing rates in the economy as a whole may be reflected sufficiently in the rate of inflation, it is the Commission's view that financing rates are a function of interest rates in the economy as a whole, which themselves are ultimately reflected in the rate of inflation. As Dr. Lowry stated:

> But the one that raises an eyebrow to me in this category is the financing of – financing rate changes. I have never seen a plan involving an index that also involves an adjustment for financing rate changes. You would think that the – there is a danger of double-counting of that since [if] there is a change in interest rates eventually it will have an effect on general inflation rates. And this is particularly so inasmuch as the other – the second inflation measure proposed by ATCO Gas is the CPI for Alberta…[181]

178. On the issue of whether changes in the cost of capital are reflected in the selected I factor, AltaGas stated in its rebuttal evidence:

> The inflation factor, like the X-factor, is designed to mirror the way prices change in a competitive economy. In a competitive economy, the price of capital inputs is determined by the real rate of return on assets, their rate of economic depreciation and the price of acquiring and installing capital. In much of productivity research, including previous productivity research conducted by us [Christensen Associates Energy Consulting] and PEG, the real rate of return has been computed using the current year's nominal rate of return and the rate of inflation in recent years. This produced significant year-over-year volatility in the real rate of return, which, in turn, led to significant year-over-year volatility in the price of capital services. With this volatility, researchers were unable to determine the trend rates of price inflation with any degree of accuracy. In recent years, researchers have noted the real rate of return fluctuates around a constant value and have taken the approach of using a fixed, real rate of return when computing capital price inflation. Fixing the real rate of return at a constant value implies the price of capital services moves in proportion to the price of acquiring and installing that capital. Thus, the relatively straight forward way of computing the inflation factor proposed by AUI is also theoretically sound.[182]

179. The theory supported by the AltaGas experts implies that changes in the cost of capital (both debt and equity) are sufficiently reflected in the company's selected inflation measure. AltaGas' proposed I factor is similar to what the Commission has adopted.

180. Accordingly, the Commission considers that a composite I factor consisting of two broad-based indexes for labour and non-labour costs captures changes in the cost of capital (both debt and equity). In addition, including a separate adjustment for the company's actual cost of capital in the I factor would require accounting for other cost items such as rate base and depreciation to determine the weighting of the capital cost component of such an I factor. In Decision 2009-035, the Commission expressed its concerns with an I factor that appeared to be an effort to move closer to an inflation index that tracked the experience of a specific company to which the PBR plan would apply rather than a broader industry inflation measure.[183] The more the selected inflation measure tracks the actual performance of an individual company, the more it resembles cost of service regulation and the more the incentive properties of PBR are

[180] Decision 2009-035, paragraphs 139-140.
[181] Transcript, Volume 14, pages 2660, line 18 to page 2661, line 2.
[182] Exhibit 477, Christensen Associates rebuttal evidence filed on behalf of AltaGas, paragraph 56.
[183] Decision 2009-035, paragraph 141.

diminished. For all these reasons, the Commission finds that no adjustments for company-specific capital costs should be incorporated in the I factor.

181. Overall, the Commission is satisfied that a composite I factor consisting of two indexes (one for labour and the other for non-labour costs), represents a reasonable balance between the need for transparency and the need for accuracy in establishing an input price inflation measure for the Alberta electric and gas distribution companies.

182. The individual components of a composite I factor are discussed below.

5.2.2 Labour input price indexes (AHE vs. AWE)

183. Some of the companies proposed using the Alberta AHE as the labour price index component of their I factors, while others preferred using the Alberta AWE instead. Both of these indexes are published by Statistics Canada. However, since the agency produces many variations of the AWE and AHE indexes, careful attention must be paid to the definition of a particular inflation measure when evaluating it.

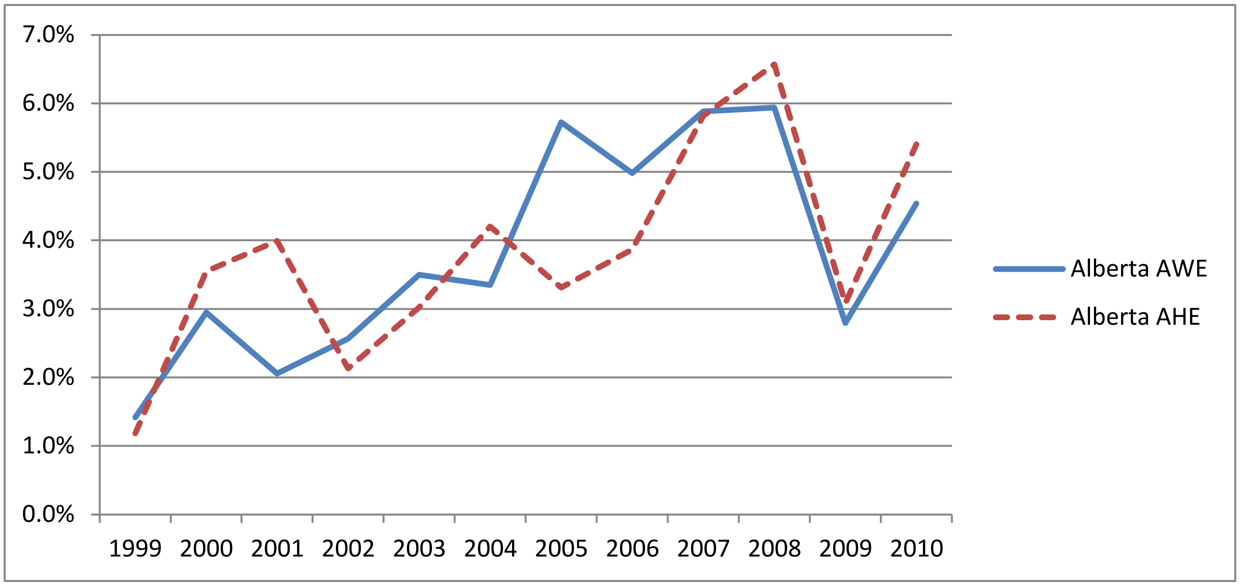
184. In their respective PBR applications, Fortis and EPCOR proposed using the AHE index, defined as average hourly earnings for salaried employees (paid a fixed salary), including overtime and unadjusted for seasonal variation, which is published for selected industries classified using the North American Industry Classification System (NAICS).[184] ATCO Electric, ATCO Gas and AltaGas proposed to use the AWE, defined as average weekly earnings, including overtime and seasonally adjusted for all employees in selected industries classified using the NAICS.[185]

185. The broadest measure for both AHE and AWE indexes is the aggregate index or industrial aggregate, which includes all NAICS industries (including utilities), except for those industries that are unclassified. As Dr. Ryan explained in his evidence, it is preferable to use either AHE or AWE for the industrial aggregate, since the weights of the individual industries in these two labour inflation indexes are not known. Further, an Alberta AHE or AWE for the utilities sector would be influenced by the companies.[186] Consequently, all the companies proposed using the AHE or AWE labour input price indexes at the industrial aggregate level.

186. In response to the Commission's information request (IR) as to whether there would be material differences in the inflation rates used for the PBR formulas if AHE or AWE were employed to calculate an I factor, the companies agreed that even though the two inflation measures may differ from each other substantially in a single year, over an extended period, both measures of labour costs increase at a similar rate. For example, Fortis pointed out that, over the period from 1999 to 2009, Alberta AHE grew by an average of 3.7 per cent annually, while Alberta AWE grew by an average of 3.8 per cent annually.[187] A similar conclusion was reached by Dr. Ryan.[188] Based on the inflation data filed by the parties, the Commission has produced the following table which compares the Alberta AHE and AWE growth rates over the period of 1999 to 2010:

184 Statistics Canada Table 281-0036, data vector V1808689.
185 Statistics Canada Table 281-0028, data vector V1597350.
186 Exhibit 103.04, Dr. Ryan evidence, paragraph 13.
187 Exhibit 219.02, AUC-ALLUTILITIES-FAI-4.
188 Exhibit 233.01, AUC-ALLUTILITIES-EDTI-4.

Table 5-3 Alberta AHE and Alberta AWE, 1999-2010 (in per cent)[189]



	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	**Average 1999-2010**
Alberta AWE	1.4	2.9	2.1	2.6	3.5	3.4	5.7	5.0	5.9	5.9	2.8	4.5	**3.8%**
Alberta AHE	1.2	3.6	4.0	2.1	3.0	4.2	3.3	3.9	5.8	6.6	3.1	5.4	**3.8%**

187. However, the companies restated their preferences for the labour index set out in their PBR applications. ATCO Electric and ATCO Gas argued that the AWE index more accurately represents their labour input costs as compared to the AHE index and therefore better meets AUC PBR Principle 4.[190] Fortis proposed to use the Alberta AHE for the labour component of the I factor, arguing that approximately 75 per cent of its employee compensation is based on an hourly rate of pay.[191] AltaGas argued that, because many of its employees and its contractors' employees are wage employees, it preferred to use the AWE index, which takes both hourly and salary compensation into account.[192] EPCOR concluded that, for the purpose of calculating an I factor to use in the PBR formulas, it is immaterial which measure is used.[193]

Commission findings

188. As EPCOR explained, both the AWE and AHE indexes are obtained from the same Statistics Canada survey[194] and therefore are based on the same underlying data. Table 5-3 above demonstrates that, over the period from 1999 to 2010, the two series yielded essentially the same overall average inflation rate.

189 For AWE, see Exhibit 540.02. For AHE, see Exhibit 233.01, AUC-ALLUTILITIES-EDTI-4.
190 Exhibit 203.01, AUC-ALLUTILITIES-AE-4 and Exhibit 204.02, AUC-ALLUTILITIES-AG-4.
191 Exhibit 219.02, AUC-ALLUTILITIES-FAI-4.
192 Exhibit 248.02, AUC-ALLUTILITIES-AUI-4.
193 Exhibit 233.01, AUC-ALLUTILITIES-EDTI-4.
194 Survey of Employment, Payrolls and Hours (SEPH).

189. The Commission observes that there is no significant difference between the Alberta AWE and Alberta AHE over an extended period of time at the industrial aggregate level and accordingly, for the purposes of establishing an I factor, either measure can be adopted.

190. Parties to this proceeding pointed out that, based on the Statistics Canada definitions of the two indexes, the main difference is that the AWE index includes both salaried employees and those paid an hourly wage while the AHE index referenced in this proceeding includes salaried employees only. In that regard, the Commission agrees with Fortis' explanation that year-to-year differences between the two measures can be explained by the fact that the adjustment of labour utilization in response to variations in economic activity are made through the number of hours worked in the short term, while salaries are slower to adjust to economic booms and slowdowns.[195]

191. In the Commission's view, using the AWE index which includes both salaried employees and those paid an hourly wage would capture the inflationary trends in labour costs more quickly than an index which includes salaried employees only. Further, given that the AWE reflects variations in economic activity sooner than the AHE, using the AWE in the composite I factor would mitigate somewhat the effect of the inflation lag resulting from using the actual inflation from the preceding 12-month period for the upcoming year's I factor, as further discussed in Section 5.3 below. In addition, the Commission observes that unlike the AWE index (from Statistics Canada Table 281-0028) that is published monthly, the AHE index (from Statistics Canada Table 281-0036) proposed by Fortis and EPCOR is published on an annual basis. As such, using the Alberta AHE index for January 1st rate changes will effectively result in a 24-month lag between the I factor used in the PBR plan and the actual labour inflation experienced by the provincial economy in any given year.

192. The other difference between the two indexes is that the proposed AWE index is seasonally adjusted, while the AHE is not. Taking into account the fact that the purpose of the seasonal adjustment is to adjust for patterns that occur within a year, the Commission agrees with the ATCO companies' view[196] that the adjustment for seasonal variation is not relevant in this case, since the companies will be using the inflation indexes over a 12-month period. Accordingly, seasonal adjustment is not a reason to choose one index over the other.

193. Finally, the Commission is satisfied that the Alberta AWE index, at the industrial aggregate level which includes all industries in the Alberta economy, is sufficiently broad-based to avoid potential concerns about the companies' actual experience significantly influencing these measures.

194. For all these reasons, the Commission considers that using the Alberta AWE index from Statistics Canada Table 281-0028, data vector V1597350 as a labour cost component of the I factor for the Alberta companies provides a reasonable overall reflection of labour price changes.

5.2.3 Non-labour input price indexes

195. In Decision 2009-035, the Commission approved the use of EUCPI as a component of ENMAX's composite I Factor. Having analyzed its recent experience under the PBR plan,

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195 Exhibit 219.02, AUC-ALLUTILITIES-FAI-4.
196 Exhibit 203.01, AUC-ALLUTILITIES-AE-4 and Exhibit 204.02, AUC-ALLUTILITIES-AG-4.

ENMAX noted that, because the EUCPI portion of its I factor is a Canada-wide index, it may not be sufficiently aligned with actual cost increases faced by an electric distribution company in Alberta.[197] The CCA also objected to the use of the unadjusted national EUCPI index in the PBR plans of the Alberta electric distribution companies.[198]

196. EPCOR, ATCO Gas and AltaGas proposed to use the all items Alberta CPI for the non-labour component of their I factors.[199] The CPI for all items is the broadest measure of the consumer price inflation, and reflects the prices of a wide variety goods and services in the economy. EPCOR, ATCO Gas and AltaGas argued that the Alberta CPI is perhaps the best index to reflect changes in their non-labour input prices. Furthermore, these companies indicated that they have traditionally used, and the Commission has adopted, the Alberta CPI in the past to forecast general supply-related costs in their cost of service rate applications. In addition, AltaGas noted that the use of the Alberta CPI reflected the fact that most of its non-labour inputs are sourced within the province.[200]

197. The proponents of the Alberta CPI generally agreed that this index may be regarded as an output rather than an input-based price index and, as such, could be influenced by the economy-wide productivity. However, as AltaGas observed, economy-wide outputs also serve as inputs in the form of goods and services purchased by companies. Additionally, Dr. Ryan, Dr. Carpenter and Dr. Schoech explained that, in the context of a composite I factor, the Alberta CPI will be used only to track changes in the prices of their non-labour inputs. Accordingly, the companies generally agreed that the Alberta CPI could be regarded as a proxy for an input price index for the purposes of their composite I factors, obviating the need for an adjustment to the TFP to calculate the X factor.[201]

198. In turn, ATCO Electric and Fortis proposed using the EUCPI for distribution systems as a price index for their non-labour input costs.[202] In her evidence, Ms. Frayer pointed out that, since the EUCPI is a national indicator, an adjustment factor was necessary to capture the differences in inflationary trends between Alberta and the Canadian average. To develop such an adjustment factor, Ms. Frayer proposed using the ratio of the Alberta to Canada GDP implicit price index (GDP-IPI) as a proxy for the inflation differential between the province and the rest of Canada.

199. After comparing the 10-year average of Alberta and Canada GDP-IPI trends for the period of 2000 to 2009, Fortis' expert recommended an adjustment factor of 29 per cent (or 1.29) per year to the national EUCPI to reflect Alberta inflation.[203] Using similar logic, and by taking a mid-point of the 10-year (2000 to 2009) and 15-year (1995 to 2009) ratios of Alberta to Canada GDP-IPI, ATCO Electric recommended an adjustment to the national EUCPI of 23 per cent (or 1.23) per year.[204]

200. The CCA supported an adjustment to EUCPI to account for the difference between Alberta and Canada inflation; however, it did not agree with ATCO Electric's and Fortis'

[197] Exhibit 297.01, ENMAX evidence, page 15.
[198] Exhibit 636, CCA argument, paragraph 46.
[199] Monthly Alberta CPI is reported in Statistics Canada Table 326-0020, data vector V41692327.
[200] Exhibit 628, AltaGas argument, page 16.
[201] Transcript, Volume 4, page 612, line 25 to page 614, line 10; Volume 8, page 1415, line 12 to page 1416, line 3. See also Exhibit 103.04, Ryan evidence, paragraph 32.
[202] Statistics Canada Table 327-0011, data vector V735224.
[203] Exhibit 100.02, prepared testimony of Julia Frayer, pages 41-43.
[204] Exhibit 98.01, ATCO Electric application, Schedule 3-3.

proposal for an adjustment. Specifically, the CCA expressed its opinion that GDP-IPI is an improper basis for comparing inflation in Alberta and Canada as a whole because price inflation in Alberta is especially sensitive to the prices of oil and gas exports, which are volatile. In PEG's view, the GDP-IPI-FDD index was more suitable for this purpose because it is less volatile that GDP-IPI index.[205] In addition, the CCA argued that, by using the most recent period of 10 to 15 years to compare price trends and adjust the Alberta EUCPI, the companies would lock in the favourable inflation differential observed in that period.[206]

201. The UCA stated that the EUCPI is more likely to represent the input capital costs of the Alberta companies because the CPI is an output measure for consumers and is wholly inappropriate for determining the I factor for the companies.[207] The UCA also contended that the EUCPI is a relevant index for gas distribution companies as well because many materials and services used in capital construction for gas distribution companies are similar to those used by electric distribution companies.[208]

202. Calgary also objected to the use of the Alberta CPI and observed that the cost components included in this index have little relevance to the cost of gas and electric distribution activities. Further, in Calgary's view, using Alberta CPI in conjunction with AWE could lead to double counting of labour costs.[209]

Commission findings

203. The Commission recognizes that using the EUCPI presents a number of problems. First, the EUCPI is a national indicator. Statistics Canada does not produce an Alberta-specific version of this index. Therefore, an adjustment to the EUCPI to account for Alberta-specific inflation must be considered. However, making such an adjustment introduces issues associated with comparing inflation in Alberta to Canada. These include whether to use levels or growth rates as the best indicator of the difference in inflation rates, whether to keep an adjustment constant or permit it to change during the PBR term and selecting an appropriate time period for such a comparison, among others.[210]

204. The ATCO companies, when commenting on an adjustment to the EUCPI proposed by PEG, submitted that such a complicated customization of the EUCPI would add complexity and confusion to a PBR plan.[211] In the Commission's view, adjusting the EUCPI introduces a high degree of subjectivity and makes the resulting I factor less transparent and more difficult to understand.

205. Additionally, as ATCO Gas and AltaGas pointed out, no construction price index similar to the EUCPI is available for gas distribution companies. The UCA contended that the EUCPI is relevant for gas companies. However, as the gas companies submitted in their arguments, it is not clear why an index covering electric distribution capital relating to substations, wires, conductors and transformers is applicable to gas distribution companies with capital costs

205 Exhibit 372.01, AUC-CCA-19(c).
206 Exhibit 372.01, AUC-CCA-19(c).
207 Exhibit 634.02, UCA argument, paragraph 81.
208 Exhibit 361.02, AUC-UCA-10.
209 Exhibit 629, Calgary argument, pages 21-22.
210 For more discussion on this issue, see Exhibit 226.01, AUC-FAI-4 and Exhibit 372.01, AUC-CCA-19.
211 Exhibit 631, ATCO Electric argument, paragraph 50 and Exhibit 632, ATCO Gas argument, paragraph 53.

relating to pipe, distribution compressors, regulators and meter stations.[212] The Commission agrees that the EUCPI should not be used as part of an I factor in a PBR plan for the gas distribution companies.

206. In the previous section of this decision the Commission agreed that the substantial influence of the oil and gas sectors on inflationary pressures in Alberta can lead to substantially different inflationary pressures than in the Canadian economy as a whole with respect to labour costs. The Commission considers that the same is true for non-labour costs. Accordingly, the Commission finds that it would be more accurate to use an Alberta measure of non-labour input price inflation.

207. If EUCPI without adjustment to reflect the Alberta environment is undesirable given the differences in inflationary pressure between Alberta and Canada as a whole, and if adjusting EUCPI to Alberta is problematic, then the Commission must consider other available indexes to adjust non-labour costs for inflation.

208. Dr. Lowry recommended using the Alberta GDP-IPI-FDD as the inflation measure for materials and services, since this index is less volatile than the Alberta CPI. However, Dr. Lowry discussed the benefits of using the GDP-IPI-FDD in the context of a customized I factor which also includes separate capital and labour components.[213] The Commission dismissed in Section 5.2.1 PEG's customized approach to setting the I factor. It is unclear whether the same benefits would be realized when this index is used for a two part I factor consisting only of labour and non-labour components.

209. Unlike the Alberta GDP-IPI-FDD, the CPI for Alberta is readily available from Statistics Canada on a regular basis and does not require any subjective adjustments or modifications. As a result, this index is easily understood by customers. While it may be argued that the Alberta CPI is less relevant to the electric and gas companies' business when used as the only inflation measure in a PBR plan, the Commission agrees with the proponents of Alberta CPI that it adequately reflects the price changes for the non-labour expenditures of Alberta companies to which it will apply. The Commission notes that the Alberta distribution companies (both gas and electric) have used the Alberta CPI as an escalator index for the non-labour items in their cost of service general tariff applications.[214]

210. The Commission agrees with the companies' experts that, because the CPI is a proxy for changes in the companies' non-labour input prices, it may be considered an input price index for the purposes of calculating a composite I factor, obviating the need for any further adjustments to TFP in deriving an X factor, as discussed in Section 6.4.1 of this decision.

211. Finally, during the hearing, the Commission inquired whether there would be a material difference to the I factors if the Alberta CPI were used instead of the adjusted EUCPI proposed by ATCO Electric and Fortis. The provided undertakings demonstrate that over the recent 10-year period, the Alberta CPI tracks very closely to the proposed adjusted EUCPI.[215]

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212 Exhibit 632, ATCO Gas argument, page 12 and Exhibit 628, AltaGas argument, page 16.

213 Exhibit 307.01, PEG evidence, page 52.

214 Exhibit 472.02, ATCO Gas rebuttal evidence, paragraph 173; Transcript, Volume 4, page 614, lines 17-19 (ATCO Electric); Transcript, Volume 11, page 2137, lines 11-18 (Fortis).

215 Exhibit 540 and Exhibit 592.

212. In light of the above considerations, the Commission is not persuaded that either the Alberta GDP-IPI-FDD or the adjusted EUCPI, with its increased complexity and subjectivity, represent a better alternative to the Alberta CPI. Accordingly, the Commission finds that the all-items Alberta CPI (from Statistics Canada Table 326-0020, data vector V41692327) should be used as a non-labour input price index in the composite I factor in the PBR plans of each of the Alberta gas and electric distribution companies.

5.2.4 Weighting of the I factor components

213. In Decision 2009-035, the Commission approved a 50:50 ratio for the components of the ENMAX's I factor by examining the company's historical cost ratios for capital and operating expenses. For the purpose of the ENMAX's I factor, the EUCPI was used to track changes in capital related costs while the AHE index was used to track changes in all O&M (operating and maintenance) expenses.[216]

214. In this proceeding, the companies have not split their costs into capital-related and O&M components for the purposes of calculating an I factor, but rather they have split them into costs driven by labour inflation and costs driven by non-labour inflation. The companies proposed that the labour and non-labour components of their I factors be weighted based on their historical proportion of labour expenditures in total combined operating and capital expenditures for the (three to five-year) period immediately preceding the PBR term.

215. The companies contended that this proposed weighting better reflects the changes in input prices that they expect to experience over the term of the PBR plan. As the ATCO companies explained:

> All labour, regardless of whether it is for capital or for O&M activities, has [the] same inflationary pressures. All workers employed by ATCO Electric or retained by ATCO Electric through a contractor exist in the same labour market here in Alberta. Labour inflation does not discriminate by whether or not the worker's pay is charged to capital or O&M. Indeed, many of ATCO Electric's staff will work on a capital project one day and an O&M project the next.[217]

216. Likewise, the companies noted that inflationary pressures on non-labour costs were likely to be the same regardless of whether they relate to O&M or capital.[218] As a result, the companies grouped their expenditures into labour costs (primarily consisting of salaries, wages and contract labour), and non labour costs (primarily consisting of materials and services) to arrive at the proportional shares for the components of their respective I factor proposals set out in Table 5-1 and Table 5-2 above.

217. The UCA supported the 50:50 weighting approved for ENMAX in Decision 2009-035 because, in Dr. Cronin and Mr. Motluk's view, this weighting reflects the capital shares in Ontario and other jurisdictions internationally.[219]

218. The CCA submitted that three weighting issues are salient in this proceeding: the denominator in the cost share calculations, the weight assigned to labour, and whether company-

[216] Decision 2009-035, paragraph 148.
[217] Exhibit 631, ATCO Electric argument, paragraph 47.
[218] Exhibit 628, AltaGas argument, page 13 and Exhibit 631, ATCO Electric argument, paragraph 48.
[219] Exhibit 634.02, UCA argument, paragraph 87.

specific costs should be used to establish weightings.[220] With respect to the first issue, the CCA did not agree with the companies using the sum of O&M and capital expenditures as the denominator in the calculation of the I factor weights. The CCA indicated that the correct denominator to be used in the composite I factor is the sum of O&M and administration expenses and capital costs, which include depreciation, return on rate base, as well as income and property taxes. The inclusion of these additional non-labour items in the total amount of costs would reduce the weight of the labour component.

219. Regarding the second issue, the CCA submitted that the weight assigned to the labour component should reflect only the share of direct labour O&M expenses in total company costs. Specifically, the CCA did not agree with the approach of including contractor expenses and capitalized labour in the labour component. The CCA pointed out that contractor expenses do not consist entirely of labour expenses. In addition, since the EUCPI and the Alberta CPI already reflect labour cost trends, the CCA argued that using these indexes for the non-labour component would result in a double counting of labour inflation. Furthermore, the CCA submitted that capitalized labour does not have the same effect on a utility's earnings as O&M expenses.[221] Dr. Lowry provided the following explanation on this subject:

> [T]he way that construction labour prices affect a utility's accounting is different from the way that the direct labour price does. The direct labour price -- let's say there's a big run-up in the price because they discovered another big oilfield or something in northern Alberta. Then by the way the O&M expenses go up. But as for the capitalized piece, that's going to be recovered over 40 years, so it does not give -- and of course the reverse is true too. If there was suddenly the price of oil collapsed […] and all of a sudden there was lower labour prices in Alberta, it immediately lowers your O&M expenses, but it does not have that much of an affect on your capital cost.[222]

220. Finally, the CCA noted that using company-specific costs to establish the weights for the I factor in the subsequent PBR plans could weaken cost containment incentives, stating that the I factor should reflect the industry-wide proportions of the relevant costs in order to provide the strongest competitive incentives. The CCA submitted that it has no objection to using company specific costs to establish the weights for the I factor in this proceeding only, provided it is clearly understood that in any future plan the cost shares will not be company-specific.[223]

Commission findings

221. The Commission explained in Section 5.2.1 of this decision that a relatively tight labour market in Alberta warrants the inclusion of a separate I factor component to reflect the unique labour inflation experience in the province. The Commission agrees with the companies that all workers employed by the companies or retained through a contractor are generally in the same Alberta labour market and subject to the same compensation inflation trends regardless of whether their work is accounted for as O&M or capital related labour.

222. Accordingly, the Commission considers that an I factor with a labour and a non-labour cost component represents an improvement over an I factor with an O&M and a capital

[220] Exhibit 636, CCA argument, paragraph 52.
[221] Exhibit 636, CCA argument, paragraph 54.
[222] Transcript, Volume 13, page 2593, line 15 to page 2594, line 4.
[223] Exhibit 636, CCA argument, paragraph 55 and Exhibit 372.01, AUC-CCA-18(a).

component, as previously approved in the ENMAX FBR plan, because it provides for a better tracking of inflation in prices of inputs that the companies use.

223. Dr. Lowry and Calgary pointed out that because both the EUCPI and the Alberta CPI include some labour, using these indexes along with the AWE or AHE indexes can result in a potential double-counting of labour inflation if all capitalized labour is removed from the non-labour category.[224] The Commission agrees. However, because no evidence was provided on the share of labour in either CPI or EUCPI,[225] correcting for any possible double-counting is problematic. One possible approach would be to adjust the weightings proposed by the companies by removing all capitalized labour as well as contractor expenses from the labour component. However, because capitalized labour and contractor expenses would comprise between 30 and 50 per cent of this component (based on the data for ATCO Electric, AltaGas and Fortis),[226] making this adjustment is tantamount to assuming that the share of labour in the Alberta CPI is between 30 and 50 per cent as well. In the absence of any information on the size of the labour component in the Alberta CPI, the Commission is not prepared to adopt this approach.

224. The CCA observed that contractor expenses do not consist entirely of labour expenses. However, as the ATCO companies pointed out, the contractors do not supply materials, and as such, their costs relate mostly to labour.[227] Similarly, Fortis also indicated that its contractor costs are "primarily labour, almost all labour."[228] AltaGas explained that because contractor costs consist of labour and services related to the use of contractor machinery, these costs tend to be driven by labour cost escalation, rather than general inflation.[229] The Commission agrees with this explanation.

225. With regard to the other concerns expressed by the CCA, such as the effect of capitalized labour on a company's earnings and whether it is necessary to include depreciation and return on rate base in the calculation of the I factor weights, the Commission observes that these proposals rely on the same rationale as the proposal to include a separate I factor component for the cost of capital. As explained in Section 5.2.1 of this decision, the Commission considers that no specific adjustments for the cost of capital need to be incorporated into the inflation index. Accordingly, the Commission accepts the companies' approach of using the sum of O&M and capital expenditures when calculating the weights for their respective I factors.

226. Finally, the Commission agrees with the CCA that, ideally, the weightings for the components comprising the I factor should reflect the industry-wide proportions of the relevant costs in order to provide the strongest competitive incentives. However, in this proceeding, the Commission was presented with no data to assess an alternative to examining the companies' own historical cost ratios relative to labour and non-labour components. For this reason, the Commission will rely on the weights calculated on the basis of the companies' historical costs, as provided in their PBR applications.

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224 Transcript, Volume 13, page 2593, lines 11-14 and Exhibit 636, CCA argument, paragraph 54.
225 For example, Dr. Ryan pointed out that Statistics Canada does not report the share of labour in the EUCPI (Exhibit 103.04, paragraph 21).
226 Estimates calculated by the Commission's staff based on the cost information provided in Exhibit 224.01; Exhibit 110.01, Appendix III, Composite I factor calculation; Exhibit 539 and referenced Rule 005 filings.
227 Exhibit 647, ATCO Electric reply argument, paragraph 76 and Exhibit 648.02, ATCO Gas reply argument, paragraph 117.
228 Transcript, Volume 11, page 2146, lines 15-18.
229 Exhibit 650, AltaGas reply argument, paragraphs 23 and 42.

227. In light of the above considerations, the Commission accepts the companies' method of calculating the weights for the I factor components. The Commission has examined the companies' historical ratios of labour to non-labour expenditures in recent years, as provided in the PBR applications and presented in tables 5-1 and 5-2 above. ATCO Electric's estimates resulted in a 65 per cent weighting of the labour component, although this ratio reflects the fact that ATCO Electric was the only company to apply a 50 per cent multiplier to its contractor costs.[230] The Commission does not agree with this adjustment. The Commission observes that the historical cost ratios are approximately 60 per cent labour and 40 per cent non-labour for the other companies (not including EPCOR). Accordingly, the Commission finds that a 60:40 weighting of the labour and non-labour components is a reasonable estimate of the balance of labour and non-labour costs for all companies, including ATCO Electric.

228. Nevertheless, the Commission has decided in the previous section of this decision to use Alberta CPI for non-labour costs. The Commission observed earlier in this section that the CPI includes some embedded labour. Therefore, using this index for the non-labour component together with the AWE index for the labour component may lead to a double-counting of labour costs. In this case, the 60:40 weighting would overstate the companies' input price inflation in years when growth in the Alberta AWE exceeds the growth in the Alberta CPI. Conversely, the companies' input price inflation would be understated in years when growth in the AWE is lower than the growth in the Alberta CPI. Accordingly, to temper the possibility that inflation in the companies' input prices will be overstated or understated, the Commission considers that a 55:45 ratio of labour to non-labour expenditures should be used for calculating the I factors in the companies' PBR plans.

229. Consistent with the findings in Decision 2009-035, in order to ensure that the companies' incentives will not be influenced by the relative rates of inflation between the components in the I factor, the Commission also finds that the 55:45 ratio of labour to non-labour expenditures should be held constant throughout the PBR term.[231]

230. EPCOR's proposed 80:20 labour to non-labour weighting reflects the company's proposal that the I-X mechanism be applied only to its non-capital related costs. As discussed in Section 2.3 of this decision, the Commission does not accept EPCOR's proposal to exclude all capital-related costs from the I-X mechanism. As such, the Commission directs EPCOR to use the 55:45 weighting in the calculation of its I factor.

5.3 Implementing the I factor

231. As the ATCO companies' expert Dr. Carpenter pointed out in his evidence, one of the difficulties in using the current year's inflation in the PBR formula is that the actual inflation indexes become available for each calendar year only in the first half of the following year, and there may not be any independent forecasts for the selected input price measures. To address this problem, Dr. Carpenter indicated that several methods could be used in practice. One method would be to accept a lag, either with or without a subsequent true up for the difference between the inflation actually experienced in a given year and the lagged inflation factor used to

[230] Exhibit 98.02, ATCO Electric application, Schedule 3-1.
[231] Decision 2009-035, paragraphs 147-148.

determine rates for that year. Alternatively, a forecast of expected inflation could be used with or without a subsequent true up to the actual inflation rate.[232]

232. ENMAX's FBR plan approved in Decision 2009-035 uses actual inflation from the previous year to set rates in a current year.[233] Specifically, ENMAX uses its selected input price indexes for the 12-month period ending December 31st of the previous year to set the I factor in the PBR formula and arrive at rates to be implemented on July 1st of the current year and to remain in effect until June 30th of the next year.[234]

233. Furthermore, in Decision 2010-146, the Commission recognized that the I factor indexes used by ENMAX may be periodically revised by Statistics Canada and ordered that these revisions be handled as a flow-through adjustment not subject to the materiality limit.[235]

234. The companies proposed two different approaches to implementing the I factor. AltaGas and EPCOR proposed to use an I factor mechanism similar to the one used by ENMAX. To accommodate the planned January 1st rate changes, AltaGas proposed that the inflation factor be calculated by computing annual price indexes for the 12-month period ending in June of the previous year. For example, in calculating rates for January 1, 2013, the AWE component of the I factor would be based on the change in the actual average AWE for the 12 months ending June 2012, as compared with the actual average AWE for the 12 months ending July 2011.[236] The UCA and Calgary agreed with this concept.[237]

235. An alternative method was put forward by ATCO Electric, ATCO Gas and Fortis and supported by the CCA. These companies proposed adopting a forecast inflation rate for the upcoming year with a subsequent revenue adjustment to true up to the actual inflation for that year. In supporting the I factor true-up approach, ATCO Gas argued that the 18-month lag between the inflation index used in the PBR formula and the actual inflation experienced by the companies could have a significant impact on its revenues, further amplified by the compounding effect of indexing. ATCO gas argued that, as a result, the inflation lag can cause windfall gains or losses, possibly triggering earnings sharing or a PBR re-opener.[238]

236. The ATCO companies also pointed out that the proposed I factor true-up does not amount to a true-up to actual companies' costs. Rather, it improves the accuracy of the inflation component of the indexing mechanism by truing up the I factor to the actual inflation index results.[239] Dr. Lowry on behalf of the CCA agreed that the use of a true-up for the actual inflation index results will produce a more accurate inflation adjustment and is warranted, particularly in light of the volatility of price inflation in Alberta.[240]

237. In contrast, AltaGas submitted that the lagged approach will be reasonably reflective of the company's input cost changes in the upcoming year and will provide a fair balance between accuracy and regulatory efficiency. As such, AltaGas argued that no I factor true-up was

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232 Exhibit 98.02, written evidence of Paul R. Carpenter, page 15.
233 In other words, in year *t* the I factor will be based on the actual inflation indexes from year *t-1*.
234 Proceeding ID No. 12, Exhibit 15, EPC amended application, page 52.
235 Decision 2010-146, paragraphs 167-168.
236 Exhibit 110.01, Appendix I - Christensen Associates report, paragraphs 32-33.
237 Exhibit 634.02, UCA argument, paragraph 88; Exhibit 629, Calgary argument, page 22.
238 Exhibit 632, ATCO Gas argument, paragraphs 60-61.
239 Exhibit 631, ATCO Electric argument, paragraph 55 and Exhibit 632, ATCO Gas argument, paragraphs 58-59.
240 Exhibit 372.01, AUC-CCA-21(a).

necessary as it introduces an unnecessary level of complexity to the PBR plan and results in additional adjustments to future rates and additional regulatory filing requirements.[241]

238. EPCOR's expert, Dr. Ryan, also commented on the redundancy of the inflation correction procedure currently employed by ENMAX which requires recalculating the previous year's inflation factor if revised data are released.[242] Dr. Ryan noted that, since Statistics Canada series revisions can extend several years into the past, this could involve substantial recalculation and subsequent adjustments of prices in previous years without any obvious overall effect, except for allocating some part of price changes to a previous or subsequent year.

239. In Dr. Ryan's opinion, the periodic revision of inflation indexes by Statistics Canada need not affect the calculation of the I factor, provided that the unrevised value is used as the basis for subsequent calculations. Dr. Ryan illustrated this concept with the following example:

> For example, if a series was 100 in Year 1 and 105 in Year 2, the inflation component for this series from Year1 to Year2 (to be used as part of the I factor in Year 3) would be 0.05 (or 5%). Now, if Statistics Canada was to revise the Year 2 series value to 104, and release the Year 3 series value of 107, then the inflation component for this series from Year 2 to Year 3 (to be used as part of the I factor in Year 4) would simply be calculated as (107- 105)/105, and no adjustment because of the change from 105 to 104 would be needed, since this effect (from 104 to 105) has already been included in the previous year's inflation component. Similarly, if the Year 2 series value was revised to 106 (rather than 105), the inflation component for this series from Year 2 to Year 3 (to be used as part of the I factor in Year 4) would still be calculated as (107-105)/105 and no adjustment because of the change from 105 to 106 in Year 2 would be needed, as this effect (from 105 to 106) would be automatically included in the subsequent year's inflation component.[243]

240. At the same time, Dr. Ryan cautioned that more substantial revisions to a component data series would need to be examined on a case-by-case basis to determine whether other adjustments would be needed. Dr. Ryan proposed that, if a termination, substantial revision or modification to a Statistics Canada data series impacted the company's inflation factor, EPCOR would be able to apply for an appropriate amendment to its inflation factor in its first annual rate adjustment filing following the termination, substantial revision or modification.[244]

Commission findings

241. EPCOR and AltaGas proposed to use the actual inflation results for the most recent 12-month period to calculate the I factor for the upcoming year with no subsequent true-up, while the ATCO companies and Fortis proposed to forecast the I factor for the upcoming year, followed by a true-up to reflect the actual inflation in that year.

242. In the Commission's view, both approaches would eventually achieve the same purpose of reflecting the inflationary pressures on the companies' input prices. Under a forecast and true-up method, the forecast I factor is reconciled to the actual inflation indexes and rates are adjusted through a regulatory proceeding. Under the alternative approach, the true-up occurs automatically by virtue of using the actual inflation indexes from the preceding year; however,

241 Exhibit 628, AltaGas argument, page 15.
242 Exhibit 103.04, Dr. Ryan evidence, paragraph 37.
243 Exhibit 103.04, Dr. Ryan evidence, paragraph 37.
244 Exhibit 103.02, EPCOR application, paragraphs 74-75.

the true up is implemented after a longer period of regulatory lag. Both approaches represent a true-up to the inflation indexes and do not imply a true-up to the actual costs of the company, thus preserving the incentive properties of the PBR regime.

243. The main difference between the two methods is that the approach preferred by the ATCO companies and Fortis ensures that the impact of actual inflation in any given year is reconciled soon after the year's end, while the alternative approach of using the actual inflation from the previous year involves a certain lag for such a true-up to occur. In this proceeding, parties' concerns with the lagged approach seemed to be centered on the fact that the lag between the inflation index used in the PBR formula and the actual inflation experienced in the economy would expose the companies to windfall gains or losses, although these would be transitory.[245]

244. The Commission considers that if inflation is higher in some years and lower in other years, as appears to be the general case in the economy,[246] then using the most recent historical inflation rate will average out the effect of any regulatory lag over the PBR period. Indeed, as ATCO Gas observed in its argument, in the absence of a true-up, the I factor in 2009 would be higher than actual inflation. The opposite would have occurred in 2010, where the I factor without the true-up would be lower than actual inflation.[247] As such, inflation will tend to balance out over the PBR term, obviating the need to true-up the I factor through a separate regulatory proceeding.

245. When discussing the benefits of the two approaches, it is important to distinguish between the fact that inflation is generally positive (in other words, prices are increasing most of the time) and the fact that the actual inflation rate will increase year-over-year in some cases and will decline in others, although prices are still increasing. For example, as Table 5-3 above demonstrates, although the level of labour prices has been increasing consistently year over year from 1999 to 2010, the rate of change in salaries and wages (i.e., labour price inflation) went up and down during this period.

246. In order for the companies to be concerned with the lagged approach and the compounding effect to take place, the rate of inflation in each year would have to be consistently higher (or lower) than in the previous year. If it is higher in some years and lower in other years, as appears to be the general case in the economy, then using the most recent past inflation rate will average out the effect of the lags over the PBR period.

247. With respect to the concern that gains or losses resulting from the inflation lag may trigger earnings sharing or a re-opener, the Commission explained in Section 10 of this decision that in order to maximize the incentive properties of the PBR plans, ESM (earnings sharing mechanism) should not be part of the companies' PBR plans. As well, as set out in Section 8 below, the Commission will examine the need for re-openers on a case by case basis. Where relevant, the consequences of the inflation lag would be considered as part of any such review.

248. In light of these considerations, the Commission finds that the lagged approach currently used by ENMAX and proposed by AltaGas and EPCOR in this proceeding represents a better alternative as compared to the forecast and true-up method proposed by the ATCO companies and Fortis. For the purposes of clarity, based on the availability of Statistics Canada indexes, the

[245] Transcript, Volume 4, pages 629-630.
[246] See, for example, the inflation indexes chart in Exhibit 512.02, AUC-Fortis-7 attachment.
[247] Exhibit 632.01, ATCO Gas argument, paragraph 61.

Commission directs the companies in their annual PBR rate adjustment filings to use the inflation indexes for the most recent 12-month period for which data is available, as specified in the formula below. The Commission considers that this approach will provide a fair balance between accuracy and regulatory efficiency and will make the companies' PBR plans more transparent and simple to understand thereby furthering the objectives of the third Commission PBR principle.

249. On the issue of the periodic revision of historical inflation indexes by Statistics Canada, the Commission agrees that Dr. Ryan's proposed method of accounting for revisions to the indexes by means of using the unrevised values in the subsequent I factor calculations represents an improvement over the rate adjustment method currently employed by ENMAX. Accordingly, the Commission finds that the periodic revision of inflation indexes by Statistics Canada need not affect the calculation of the I factor and directs the companies to use the unrevised actual index values from the prior year's I factor filing as the basis for the next year's inflation factor calculations.

250. The Commission also agrees with Dr. Ryan's recommendation that if a termination, substantial revision or substantial modification to the Statistics Canada data series used in the companies' I factors occurs, such changes should be brought forward to the Commission as part of the annual PBR rate adjustment filings. Any changes to the I factors arising from such data series modifications will be dealt with on a on a case-by-case basis.

5.4 Commission directions on the I factor

251. The Commission directs that the I factor to be used in the PBR plans of the Alberta utilities shall be calculated as follows:

$$I_t = 55\% \text{ x } AWE_{t-1} + 45\% \text{ x } CPI_{t-1},$$

where:

I_t	Inflation factor for the following year.
AWE_{t-1}	Alberta average weekly earnings index for the previous July through June period.[248]
CPI_{t-1}	Alberta consumer price index for the previous July through June period.[249]

6 X factor

6.1 Purpose of the X factor

252. The X factor is one of the key elements of PBR plans employing an I-X indexing mechanism to adjust a regulated company's prices or revenues each year during the PBR term. In general terms, the X factor can be viewed as the expected annual productivity growth during the

[248] The selection of the start and ending months for the 12-month period reflects the latest published Statistics Canada data prior to September.

[249] The Commission recognizes that Alberta CPI information for July may be available when the September annual PBR rate adjustment filing is made but the Commission is directing the July through June period in order to ensure the companies have enough time to prepare their filings.

PBR term. Through the I-X mechanism, a PBR plan is designed so that the changes in the prices of the company's distribution services reflect changes in input prices as reflected by the I factor and the rate of expected productivity growth.

253. The X factor, combined with the I factor, is designed to mirror the pressures of competitive market forces. In competitive markets, firms are not able to earn additional profits from productivity improvements that their competitors also adopt because competition acts to drive down prices.[250] However, to the extent that the firm is more productive than its competitors, it earns an extra return, which serves as a reward for its better than average productivity. Conversely, firms that are less productive than average earn lower returns.[251] The X factor in a PBR plan imitates these pressures by requiring the regulated companies to adjust their prices to reflect the expected productivity growth.

254. NERA and other experts in this proceeding drew attention to the fact that the magnitude of the X factor has no influence on the incentives for the company to reduce costs.[252] As Dr. Carpenter explained in his evidence:

> Under PBR, a utility which successfully saves a dollar of operating expenditure keeps that dollar (or a portion of the dollar under an earnings sharing mechanism). The opportunity to save the dollar (or portion thereof) of expenditure is unrelated to the level of rates, and therefore the magnitude of the productivity factor does not influence the incentive to find the savings.[253]

255. AltaGas explained that while the size of the X factor does have an impact on the company's return, it is the decoupling of the revenues and prices from the company-specific costs that provide the incentives, rather than the magnitude of the X factor itself.[254] Similarly, EPCOR and the CCA noted that it is the length of the term of the PBR plan (i.e., regulatory lag) that is the primary source of the incentives.[255]

Commission findings

256. During the term of the PBR, a company's prices or revenues will change with inflation, represented by the I factor, adjusted by the expected productivity growth represented by the X factor. Customers of a regulated company under PBR directly benefit from annual rates that are adjusted to reflect this expected productivity growth.

257. The Commission agrees with the experts of the companies, NERA and the CCA, that while the size of the X factor affects a company's earnings, it has no influence on the incentives for the company to reduce costs. As the companies' and the CCA's experts pointed out, the PBR plans derive their incentives from the decoupling of a company's revenues from its costs as well as from the length of time of the PBR term, and not from the magnitude of the X factor itself.

[250] Exhibit 98.02, Carpenter evidence, page 18.
[251] Exhibit 616.02, page 13, William J. Baumol, "Productivity Incentive Clauses and Rate Adjustment for Inflation," *Public Utilities FORTNIGHTLY*, (22 Jul. 1982).
[252] Transcript, Volume 1, page 117, lines 10-15; Exhibit 633, Fortis argument, paragraphs 140-141.
[253] Exhibit 98.02, Carpenter evidence, page 17.
[254] Exhibit 628, AltaGas argument, page 32.
[255] Exhibit 630.02, EPCOR argument, paragraph 80; Exhibit 636, CCA argument, paragraph 105.

6.2 Approaches to determining the X factor

258. As the record of this proceeding demonstrates, there are different approaches to setting the productivity target included in the X factor of a PBR plan. In Decision 2009-035, the Commission expressed its preference for an approach to determining the X factor that is based on the average rate of productivity growth in the industry as a whole.[256] As NERA explained, under this concept, the purpose of the X factor is to reflect the long-term underlying industry productivity trend.[257] NERA favoured this approach to the determination of the X factor as evidenced by the two reports[258] prepared by NERA on total factor productivity for the regulated electric utility industry. While differing from NERA on how to determine the underlying industry productivity trend, EPCOR, AltaGas and the ATCO companies used this approach to setting the X factor.[259]

259. The CCA generally agreed with NERA's opinion that the X factor should reflect the productivity growth of the industry in which the company operates. In addition to using the index approach employed by NERA for estimating the industry productivity trend, the CCA's experts relied on an econometric model for this purpose as well. In PEG's view, the econometric approach produces a more customized productivity estimate reflecting Alberta business conditions.[260] The econometric approach to measuring TFP is further discussed in Section 6.3.4 below.

260. In Fortis' view, the analysis of the historical industry productivity trend needs to be complemented with an assessment of a company's going-forward costs and especially capital expenditure costs.[261] NERA pointed out that this type of X factor derivation resembles the building blocks concept currently employed by regulators in the United Kingdom and Australia. Under this approach, the X factor does not come from a TFP growth study, rather it is calculated as the value that would set the customer rates at a level to recover the company's cost of service revenue requirement over a forecast period.[262] Fortis' expert, Ms. Frayer, explained that in these circumstances, the X factor represents not a productivity factor itself, but rather a smoothing factor for rates, while the productivity target is embedded in the forecast of future operating and capital costs that are then used to forecast a revenue requirement and rate schedule.[263]

261. The UCA's preferred approach to determining the X factor centered upon efficiency benchmarking and consideration of a level of inefficiency for each particular company.[264] Under this method, the regulator must perform a benchmarking assessment of historical efficiency for a comparator group of companies, based upon a comprehensive analysis of their costs including capital, labour, materials and power losses. Following this analysis, the companies are assigned different productivity targets that are set higher, the more inefficient any particular company was

256 Decision 2009-035, paragraph 176.
257 Exhibit 391.02, NERA second report, paragraph 36.
258 Exhibit 80.02, NERA report and Exhibit 391.02, NERA second report.
259 Exhibit 630.02, EPCOR argument, paragraph 67; Exhibit 628, AltaGas argument, page 29; Exhibit 631, ATCO Electric argument, paragraph 84; Exhibit 632, ATCO Gas argument, paragraph 94.
260 Transcript, Volume 13, pages 2529-2530.
261 Transcript, Volume 11, page 2104, lines 23-24 and Exhibit 474.01, Fortis rebuttal evidence, paragraph 19.
262 Exhibit 391.02, NERA second report, pages 27-28.
263 Exhibit 474.02, Frayer rebuttal, page 38.
264 Transcript, Volume 17, page 3167, line 1 and Exhibit 299.02, Cronin and Motluk UCA evidence, pages 117-125.

found to be as compared to its peers (or, in other words, the further away a company was found to be from the efficiency frontier).[265]

262. In the absence of a complete set of the detailed historical cost information for Alberta gas and electric distribution companies upon which to base the benchmarking assessment, the UCA experts recommended constructing a menu which pairs data on a range of probable productivity performances with the associated ROE (return on equity) that would be permitted with each productivity choice. In the UCA's view, the menu approach to the X factor would mitigate the risks from information asymmetry and incent the companies to reveal their performance potential.[266]

263. For practical purposes, Dr. Cronin and Mr. Motluk recommended the use of the X factor and ROE menu discussed in the Ontario Energy Board's *2000 Draft Rate Handbook*.[267] This menu was based on the analysis of the performance of 48 distribution utilities in Ontario operating under the cost of service (1988 to 1993) and PBR (1993 to 1997) regimes.[268] The UCA's X factor menu recommendation is as follows:

Table 6-1 The X factor menu proposed by the UCA's experts[269]

Selection	X factor (in per cent)	ROE ceiling (in per cent)
A	1.25	10
B	1.50	11
C	1.75	12
D	2.00	13
E	2.25	14
F	2.50	15

264. Dr. Cronin and Mr. Motluk explained that under this arrangement, the companies can choose a combination of productivity growth and ROE: a higher productivity target would permit higher returns.[270] The UCA experts explained that the menu above has an earnings sharing mechanism embedded in it. In particular, the menu selections were designed in such as way that moving among menu choices (for example, from option A to option B) results in a 57:43 earnings sharing between a company and the ratepayers. At the same time, if a company's actual ROE exceeds the earnings ceiling associated with a particular menu option, 100 per cent of earnings above the ROE cap is given to ratepayers.[271]

Commission findings

265. NERA explained that because in competitive markets prices move according to the productivity of the industry in question rather than the particular costs of one company, it has

265 Exhibit 299.02, Cronin and Motluk UCA evidence, pages 131-136.
266 Exhibit 299.02, Cronin and Motluk UCA evidence, pages 140-141.
267 http://www.oeb.gov.on.ca/documents/cases/RP-1999-0034/handbook0.html.
268 Exhibit 299.02, Cronin and Motluk UCA evidence, page 154.
269 Exhibit 299.02, Cronin and Motluk UCA evidence, page 154.
270 Exhibit 299.02, Cronin and Motluk UCA evidence, pages 153 and 154.
271 Transcript, Volume 17, page 3205, lines 11-20.

become customary for regulators in the design of objective PBR formulas to set the X factor based on the underlying trend in industry productivity growth.[272]

266. Similarly to the discussion in the proceeding dealing with ENMAX's FBR plan, in this proceeding the parties offered several principal approaches to determining the X factor. With respect to Fortis' approach, which involved setting the X factor based on the forecast revenue requirement over the PBR term, the Commission agrees with NERA's characterization that this method essentially resembles a five-year test period under traditional cost of service rate making.[273]

267. The Fortis approach first determines the forecast revenue requirement over the PBR term and then develops a formula to be applied to rates which will yield the forecasted revenue requirement each year. As NERA observed, while Fortis' approach resembles the practices of regulators in the United Kingdom and Australia, it is inconsistent with the institutional foundation for performance-based-rate regulation generally adopted in Canada and the United States.[274] Accordingly, the Commission restates its opinion expressed in Decision 2009-035 that this method effectively involves a multi-year cost of service rate setting exercise and changes the theoretical basis for utilizing the X factor, which is to emulate the incentives of a competitive marketplace for the benefit of ratepayers and shareholders alike.[275]

268. The efficiency frontier and benchmarking method advocated by the UCA's experts represents yet another approach to determining the value of the X factor. In contrast to productivity studies that deal with the rate of industry productivity growth over time, the efficiency frontier analysis focuses on a company's productivity level (i.e., efficiency[276]) at a particular time in relation to comparable companies. In other words, instead of looking at how the industry's productivity changes over time, this method examines whether one particular company is less or more efficient at the time of measurement as compared to its peers.

269. In the Commission's view, the efficiency benchmarking analysis is prone to two major criticisms. First, as NERA and Dr. Carpenter explained, the efficiency levels are hard to estimate as this type of analysis requires a multitude of historical company-specific data, which exhibit a great deal of year to year volatility and are prone to errors.[277] Indeed, as the UCA witnesses observed, this method of developing the X factor would busy "hundreds of analysts" both of the companies and the regulator.[278]

270. More importantly, Dr. Makholm and Dr. Carpenter pointed out that in practice it is virtually impossible to determine whether a firm is or is not efficient by looking at benchmark data alone, since relative efficiency depends on a boundless number of variables, both observable

[272] Exhibit 80.02, NERA report, pages 1 and 3.
[273] Exhibit 195.01, AUC-NERA-9(a).
[274] Exhibit 391.02, NERA second report, page 9.
[275] Decision 2009-035, paragraph 174.
[276] The difference between terms "productivity" and "efficiency" is a definitional one. Dr. Makholm agreed when people refer to productivity, they usually refer to productivity growth, and they just leave out the word "growth" because productivity growth is measured in a percentage and some people confuse productivity growth with the actual efficiency at a point in time or the efficiency of one company. (Transcript, Volume 3, page 528, lines 5-25.)
[277] Transcript, Volume 3, pages 490-491 and Volume 7, pages 1244-1245.
[278] Transcript, Volume 17, page 3227 and pages 3430-3431.

and unobservable.[279] Factors such as age of plant, soil type, weather and geography, customer density, etc., are to be taken into account when considering efficiency levels. In these circumstances, inadvertently leaving out an important productivity driver may invalidate the results of the study.[280] Overall, the Commission agrees with the following criticism by NERA of the UCA's approach:

> So if you get into the business of drawing a productivity frontier and concluding that you know why a company is not on that frontier, that is, it's inefficient, you're making two errors. One, the error is concluding that you've actually measured a frontier, and we contend that, to a certain extent, you're measuring errors. And the second is that we economists have anything to say about whether a firm is or is not productive with the scarcity of data we have before us. Could be that you don't lie in the efficiency frontier because your utility is in a swamp. But if we can't measure swampiness, we have no way of correcting for that.[281]

271. In contrast, because TFP (total factor productivity) studies (such as the one prepared by NERA in this proceeding) focus on rates of change in productivity within an industry, not levels, the unique cost features of any particular company cancel out in the process. In other words, these productivity studies do not examine whether one firm has a greater level of output for the same inputs levels as another firm. Rather, the focus is to study how the ratio of outputs to inputs changes over time for the industry as a whole.

272. Under the UCA's efficiency benchmarking approach to developing the X factor, a company is incented to catch up to the level of efficiency experienced by peer companies deemed to be more efficient by the regulator, rather than to meet or beat the industry rate of productivity growth. Because of the practical and theoretical problems associated with measuring efficiency levels described above, the Commission does not accept this approach for the purposes of PBR in Alberta.

273. With respect to the menu approach to setting the X factor proposed as an alternative by the UCA's experts, for the reasons outlined below, the Commission is not prepared to adopt this approach.

274. First, similar to a discussion in sections 6.3.3 and 6.3.7 of this decision, the Commission is not persuaded that the UCA's X factors, based on ten-year data for Ontario distribution companies, represent a better indicator of the underlying long-term industry productivity trend than NERA's TFP based on a broad sample of companies over the period of 1972 to 2009. Second, as ATCO Electric pointed out, it is not clear why the X factor/ROE tradeoffs presented in the menu were reasonable for the Alberta companies.[282] In particular, the ROE ceilings in the menu do not correspond to the Commission's determinations in the most recent Generic Cost of Capital decision.[283] In addition, EPCOR pointed out that the UCA's menu approach presupposes the inclusion of an ESM (earnings sharing mechanism) in the PBR design.[284] The Commission determines in Section 10 of this decision that in order to maximize the incentive properties of PBR, an ESM should not be part of the companies' plans.

279 Transcript, Volume 3, pages 490-491 and Volume 7, pages 1244-1245.
280 Transcript, Volume 18, pages 3482-3483.
281 Transcript, Volume 3, page 491, line 20 to page 492, line 6.
282 Exhibit 647, ATCO Electric argument, paragraph 123.
283 Transcript, Volume 17, pages 3204-3205.
284 Exhibit 646.02, EPCOR reply argument, paragraph 74.

275. In addition, the Commission observes that the Ontario Energy Board did not accept the menu approach, partly because of the concerns regarding "the unnecessary complexity encompassed in the proposed menu."[285] A similar concern was expressed by EPCOR's expert, Dr. Weisman, who supported his view with the following quotation from an academic article:[286]

> Allowing for a choice among incentive plans can complicate the regulatory task, thereby sacrificing simplicity. The costs of reduced simplicity must be weighed against the expected gains from creating "win-win" situations.[287]

276. The Commission shares these concerns. In the Commission's view, the UCA's menu approach does not conform to AUC Principle 3, which requires, among other things, that a PBR plan should be easy to understand, implement and administer. Based on the above considerations, the Commission does not accept the menu approach proposed by the UCA.

277. The Commission restates the preference expressed in Decision 2009-035 for an approach to setting the X factor that is based on the long-term rate of productivity growth in the industry. During the hearing, NERA explained the rationale behind this approach as follows:

> The theory that we're drawing from doesn't require such precision. It says that there is an industry out there that's doing something. If it's a competitive industry -- it's an industry for making [hockey sticks], I don't know. [...] And of all the makers of hockey sticks, there's a productivity trend for hockey stick makers, and if you can't keep up, your business will fail. We don't need to be vastly more sophisticated than to measure the productivity of the hockey stick industry and use that as our way of allowing regulatory lag to eke out a few more years to avoid a couple of rate cases and to allow a little more productivity pressure to be visited on utility managements to try to make the businesses run better.[288]

278. As NERA emphasized, this concept corresponds to the underlying theory behind the PBR plans in Canada and the United States: to permit regulated prices to change to reflect general price changes and industry productivity movements without the need for a base rate case. The effect is to lengthen regulatory lag and better expose regulated utilities to the type of incentives faced by competitive firms.[289]

279. Given the approach approved above, the starting point for determining the X factor is to estimate the underlying industry TFP growth for the services included in the companies' PBR plans. Then, it is necessary to consider any adjustments to the industry TFP that may be required to arrive at an X factor for Alberta gas and electric distribution companies. And finally, the Commission will consider whether a stretch factor is justified and if so, the size of a stretch factor. Sections 6.3 to 6.5 below deal with each of these steps.

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285 Exhibit 299.02, Cronin and Motluk UCA evidence, page 174.
286 Sappington, David E. M., *Designing Incentive Regulation.* Review of Industrial Organization, Volume 9, 1994, page 260.
287 Exhibit 473.09, rebuttal testimony of Dennis L. Weisman, Ph.D., page 16.
288 Transcript, Volume 3, page 476, line 17 to page 477, line 5.
289 Exhibit 391.02, NERA second report, paragraph 2.

6.3 Total factor productivity

6.3.1 The purpose of total factor productivity studies

280. As set out in the previous section of this decision, the Commission opted for an approach to set the X factor based on the average rate of productivity growth in the industry. Under this approach, the first step in determining the X factor is to examine the TFP (total factor productivity) of the electric and gas distribution industries.

281. For this purpose, the Commission engaged NERA to conduct a TFP study applicable to Alberta gas and electric companies.[290] NERA filed its report entitled "Total Factor Productivity Study for Use in AUC Proceeding 566 – Rate Regulation Initiative" dated December 30, 2010 as Exhibit 80.02. The study was based on a population of 72 U.S. electric and combination electric/gas companies from 1972 to 2009. NERA measured the TFP of the distribution component of the electric companies. Costs related to power generation and transmission, as well as general overhead costs, were not included in the study.[291]

282. In addition to NERA's study, PEG on behalf of the CCA performed a TFP also referred to as a multifactor productivity (MFP)[292] study for the gas distribution industry. PEG's analysis examined the productivity growth of 34 U.S. gas distribution companies for the period from 1996 to 2009. In its study, PEG calculated the TFP trends of the sampled companied as providers of gas transmission, storage, distribution, metering and general administration services.[293]

283. In its report, NERA explained that productivity growth for a particular firm, by definition, is the difference between the growth rates of a firm's physical outputs and physical inputs. That is, to the extent that a firm's productivity grows, it will transform its inputs into a greater level of output. Accordingly, the task of productivity measurement involves comparing a firm's outputs and inputs over time. Total factor productivity measures all of a firm's inputs and outputs, combining the various inputs and outputs into single input and output indexes suitable for comparison to one another for purposes of measuring the rate of productivity growth over time.[294]

284. NERA pointed out that the main purpose of the TFP growth study is to measure the underlying long-term trend in industry productivity growth.[295] The UCA agreed with NERA that TFP should reflect long-term productivity growth.[296] Similarly, ATCO Electric and ATCO Gas expressed their understanding that a TFP study produces an estimate of the long-term TFP growth of the industry. At the same time, the ATCO companies cautioned that in using the TFP result as a starting point for determining the X factor in a PBR plan, it is necessary to

290 Exhibit 71.01, AUC letter – Retention of Consultant to Develop Basic X Factor, September 8, 2012.
291 Exhibit 80.02, NERA report, page 6.
292 Dr. Lowry explained that, strictly speaking, MFP is a more accurate term than TFP, since the latter implies that all of the company's inputs are taken into account in its computation, which is often not possible or practical to do. However, Dr. Lowry agreed that generally these terms can be used interchangeably. MFP is the term used by Statistics Canada (Transcript, Volume 13, page 2451).
293 Exhibit 307.01, PEG evidence, page 2.
294 Exhibit 80.02, NERA report, page 5.
295 Exhibit 391.02, NERA second report, paragraph 38.
296 Exhibit 634.02, UCA argument, page 21, paragraph 117.

consider whether the historical long-term productivity trend of the industry is a reasonable estimate of the expected productivity growth of the utility during the PBR plan term.[297]

285. EPCOR concurred that the purpose of the TFP is to assist in determining what productivity growth is expected to be over the course of the PBR term.[298] In contrast, IPCAA contended that TFP analyses have no apparent relevance to electric distribution system economics, save as broad long-term overall indicators.[299] However, IPCAA's concerns in this regard appeared to center on the fact that TFP studies rely on energy throughput as an output measure, as further discussed in Section 6.3.6 of this decision.

286. In Fortis' view, since statutory requirements must take precedence over other ratemaking principles, the TFP study should not be the core foundation for the Commission's determination of the X factor. Specifically, Fortis submitted that because the Alberta statutory framework under the *Electric Utilities Act*, SA 2003, c. E-5.1, mandates that the rates being set must provide a reasonable opportunity to recover the prudent costs of the provision of the regulated service, and because rates are being set for the initial PBR term, expectations as to the achievable productivity growth for the PBR term must prevail over considerations of the long-term industry productivity growth.[300]

Commission findings

287. As set out in Section 6.2 above, the objective of the PBR plan sought by the Commission is to emulate the incentives experienced by companies in competitive markets where prices move according to the productivity of the industry in question rather than with the particular costs of a company. Under this approach, the first step in determining the X factor is to examine the underlying industry productivity growth over time, commonly measured by total factor productivity.

288. Accordingly, the Commission agrees with NERA that, in these circumstances, the purpose of the TFP study is to estimate the long term productivity growth of the industry in question.[301]

289. The Commission does not share Fortis' view that expectations as to the achievable productivity growth for the PBR term must prevail over considerations of the industry TFP when determining the X factor. In the Commission's view, Fortis' submission is reflective of the company's overall approach to determining the X factor as a mechanism to recover the forecast cost of service revenue requirement over the PBR term. As set out in Section 6.2 above, the Commission does not agree with this approach.

290. Fortis emphasized that the *Electric Utilities Act* stipulates that the companies' rates must provide a reasonable opportunity to recover the prudent costs of the provision of the regulated service. In the Commission's view forecasting the projected revenue requirement over a PBR term is not the only way to satisfy this statutory mandate. In that regard, the Commission agrees with NERA's explanation that the rationale behind the X factor (to which the TFP study contributes) is to emulate the incentives of competitive markets as they relate to productivity. In

[297] Exhibit 631, ATCO Electric argument, paragraph 81 and Exhibit 632, ATCO Gas argument, paragraph 90.
[298] Exhibit 630.02, EPCOR argument, paragraph 62.
[299] Exhibit 306.01, Vidya Knowledge Systems evidence, page 5.
[300] Exhibit 633, Fortis argument, paragraphs 100-103.
[301] Exhibit 391.02, NERA second report, paragraph 38.

competitive markets, if a company achieves greater productivity growth than the industry, it is rewarded by larger earnings in the short run. If a company's productivity growth is lower than the industry productivity, its earning suffer in the short run.[302] Accordingly, in the Commission's view, the approach to determining the X factor based on the average productivity growth in the industry together with the selection of the I factor and the other features of the approved PBR plans provide regulated companies with a reasonable opportunity to recover their prudent costs of providing the regulated services.

6.3.2 Relevant time period for determining the TFP

291. The appropriate time period over which to calculate TFP for purposes of the companies' PBR plans garnered much attention in this proceeding. NERA recommended the use of its full set of data from 1972 to 2009, being the longest time period available from the Federal Energy Regulatory Commission (FERC) Form 1 dataset that NERA relied on.[303] The majority of other parties recommended a substantially shorter period.

292. NERA pointed out that the TFP growth analysis should span a sufficient number of years to mitigate the effects of business cycles or other idiosyncratic swings associated with annual changes in the use of inputs and outputs, for example, major capital replacements. Consequently, NERA argued that the more years of data that are added to the study, the more the effects of year-to-year changes in TFP growth are moderated and a picture of long-term productivity growth emerges.[304] As a result, NERA's TFP calculation was based on the 38 years of available data.

293. In its second report NERA provided additional reasons in support of its position to use the longest time period available. NERA pointed out that in a competitive market, from which the incentives inherent in PBR plans are drawn, equilibrium prices are affected only by changes in long-run average cost. Short-run changes in productivity, even industry-wide changes in productivity, do not cause firms to enter or leave an industry.

294. Furthermore, on the issue of whether a more recent period is more reflective of the expected productivity growth in the coming years as advocated by most other parties, NERA argued that unless there is reliable proof to the contrary, the best and most supportable economic assumption is that while productivity growth may fluctuate in an erratic manner in the short term, or in a longer-term cyclical manner, it will eventually revert back to its long-term underlying trend.[305]

295. NERA noted that if one suspects that any of the TFP growth series are not stable in the long term (thereby justifying a departure from the use of long-term industry data), the appropriate response to such suspicion is to implement a statistical testing procedure in accordance with accepted research in the area of "structural breaks." In that regard, NERA experts explained that such analysis involves a two-step process: first, it is necessary to postulate a theory about why a structural break could have occurred, and, second, it is necessary to perform a number of statistical tests to see if the postulated hypothesis is supported by the data.[306] Dr. Makholm emphasized that performing an ex post statistical analysis of visual data without

302 Exhibit 195.01, AUC-NERA-8(a).
303 Transcript, Volume 1, pages 44-47.
304 Exhibit 80.02, NERA report, page 6.
305 Exhibit 391.02, NERA second report, page 14.
306 Transcript, Volume 1, pages 81-85.

having a supportable hypothesis for a structural break harms the process and biases the researcher.[307]

296. Dr. Makholm observed that he was not aware of any academic studies that would suggest that a structural break occurred at any time within the 1972 to 2009 time period for which data were available with respect to the electric distribution industry in North America.[308] As a result, NERA supported the use of the full time period as the most objective basis for the TFP calculation. Calgary supported this position.[309]

297. The companies' experts contended that NERA's sample period, especially the early part of it, was not relevant for estimating the industry's current TFP trends or the trends that might be expected to prevail during the PBR term. Specifically, ATCO and EPCOR experts in their respective evidence pointed out that in the 1970s and 1980s, the utilities sector was vertically integrated, owning and operating generation facilities with little wholesale and no retail competition. Dr. Carpenter and Dr. Cicchetti concluded that productivity improvements pertaining to the vertically integrated utilities observed in the early part of NERA's study period were unlikely to be realized by today's unbundled distribution companies and as a result, a more recent period should be used for estimating the industry TFP.[310]

298. Furthermore, to test NERA's conclusion that a structural break had not occurred in the electric distribution industry, Dr. Cicchetti performed a number of statistical tests on NERA's productivity data and found that the TFP growth in the 1999 to 2009 period was statistically different than in prior years. Dr. Cicchetti concluded that a structural break occurred in 1999 and, therefore, a more recent period should be used for the purpose of the TFP and X factor determinations.[311]

299. Ms. Frayer on behalf of Fortis also noted that there have been structural changes in the electric utility sector involving changes in investment trends, technology deployment, operating practices, customer consumption patterns, and regulatory incentives. In addition, Fortis' expert indicated that as industries and firms get more and more efficient, it is unreasonable to assume that they should sustain the same level of productivity growth over time. Accordingly, Ms. Frayer's analysis was mostly based on the data from the years 2000 to 2009.[312]

300. In the same vein, based on their observation of the cumulative rate of TFP growth, AltaGas experts argued that a significant break in the productivity trend occurred around the year 2000. Specifically, Dr. Schoech observed that prior to 2000, the TFP for the U.S. electricity distributors in the NERA study grew at a substantial 1.6 per cent, while since 2000, the TFP has been declining at the approximate rate of -1.4 per cent. Similar to the other companies' experts, Dr. Schoech offered restructuring of the industry and changing consumption patterns as possible explanations for changes in the productivity.[313]

301. In developing their recommendations as to the relevant time period for the TFP calculations, the companies' experts also considered regulatory precedents. Dr. Cicchetti noted

[307] Transcript, Volume 1, page 88, lines 7-15 and page 95, lines 11-19.
[308] Transcript, Volume 1, page 91, line 23 to page 92, line 2.
[309] Exhibit 629, Calgary argument, page 23.
[310] Exhibit 103.05 Cicchetti evidence, page 10 and Exhibit 98.02, Carpenter evidence, page 21.
[311] Exhibit 473.07, Cicchetti rebuttal evidence, page 14.
[312] Exhibit 474.02, Frayer rebuttal evidence, pages 18-20 and Exhibit 100.02, Frayer evidence, page 79.
[313] Exhibit 110.01, Christensen associates evidence, pages 11-12.

that based on his experience with PBR plans for energy utilities, the typical range for estimating the industry TFP growth is about 10 to 11 years.[314] Dr. Carpenter indicated that other TFP studies that he had seen generally use time frames no longer than 10 to 15 years.[315] Ms. Frayer pointed to a number of TFP studies used by other regulators with sample periods from four to 13 years.[316]

302. PEG agreed that there is some value in a shorter period because even long term drivers of TFP growth such as technological change can vary over a period of several decades. Dr. Lowry noted that in the past he often advocated a period of at least 10 years, but recent empirical results and NERA's testimony persuaded him that a minimum of 15 years is typically more desirable.[317]

303. In reviewing NERA's TFP estimate, PEG submitted that the relevant time period should essentially focus on the concept of a business cycle. As Dr. Lowry explained, because NERA's study used delivery volumes as an output measure, the resulting TFP is highly sensitive to changes in economic conditions. Therefore, Dr. Lowry advocated that when choosing the relevant time period, it is necessary to choose a start and end date that are at a similar point with respect to the business cycle, so that the key demand drivers are at the same levels.[318]

304. In that regard, Dr. Lowry observed that the last two years in NERA's sample, 2008 to 2009, were characterized by a deep recession and he recommended excluding these years to avoid distorting the long-run TFP trend. As a result, the CCA expert recommended a sample period for NERA's TFP study that ends in 2007 (avoiding the two recession years) and begins in 1988, a year with similar values for two key volume driver variables, cooling degree days and the unemployment rate.[319] For the purpose of its MFP study of U.S. gas distribution companies, PEG used the sample period of 14 years from 1996 to 2009 based on Dr. Lowry' judgment and experience.[320] PEG noted that this was the longest period available for the dataset on which PEG relied.[321] The CCA's expert explained that a 2009 sample end date was acceptable in this case, since his study did not use a volumetric output index and therefore would not be subject to volume related impacts of the 2008 to 2009 recession.

305. With respect to the 10 to 15-year timeframes advocated by the companies' experts relying on the NERA study, PEG contended that the suggested sample periods do not have an objective basis. In particular, Dr. Lowry noted that the companies have provided no credible explanation of why the sample period should begin just as the period of slower productivity growth begins. Moreover, Dr. Lowry reiterated his opinion that if a substantially shorter sample period (e.g., 10 to 15 years) such as those advocated by company witnesses is to be entertained, the exclusion of the 2008 to 2009 recession years becomes imperative for recognition of a long-term trend given the volumetric output index utilized in the NERA study.[322]

314 Exhibit 103.05 Cicchetti evidence, paragraph 18.
315 Exhibit 98.02, Carpenter evidence, page 25.
316 Exhibit 474.02, Frayer rebuttal evidence, page 21.
317 Transcript, Volume 13, pages 2490-2491.
318 Transcript, Volume 13, pages 2490-2491 and pages 2502-2503.
319 Exhibit 569.01, PEG evidence errata, page 9.
320 Transcript, Volume 13, pages 2490-2491.
321 Exhibit 372.01, AUC-CCA-5(a).
322 Exhibit 569.01, PEG evidence errata, pages 7-9.

Commission findings

306. The length of a sample period can be a critical issue when indexes are used to estimate long run productivity trends, as demonstrated by the fact that just removing the last two years from NERA's sample period raises the TFP growth trend from 0.96 to 1.13 per cent.[323] The CCA submitted that when selecting the relevant sample period for a TFP study, the following two objectives must be considered:

- smooth out the effect of cost and output volatility
- capture the TFP growth trend that is most likely to be pertinent during the PBR plan period[324]

307. Most experts in this proceeding agreed that the time period for the TFP measurement should be long enough to smooth out the inevitable year-to-year variation in results that obscures the long term productivity trend of the industry.[325] As Ms. Frayer observed, specific annual circumstances with respect to weather and consumption, capital spending, labour, etc., contribute to the volatility of year-to-year TFP numbers.[326] There appeared to be an agreement among the parties that a sample period of at least 10 years is desirable for the purpose of determining the long-term industry TFP.[327]

308. However, much of the debate in this proceeding was centered on the issue of what historical time period to use to predict the productivity growth likely to be experienced by the industry during the PBR term. NERA's experts contended that unless the TFP growth series is not stable in the long term, as demonstrated by a structural break, the best economic assumption is that the industry productivity growth will eventually revert back to its long-term underlying trend.[328] Therefore, the use of the longest time period for which data is available is warranted absent evidence of a structural break in the productivity of the industry.

309. While accepting that a long-term productivity measure is required, the companies' experts contended that the period recommended by NERA was too long. These experts pointed to a number of changes in the electric distribution industry over time, of which the unbundling of distribution and generation facilities and the introduction of retail competition in the mid 1990s were the most significant, and suggested that the underlying industry TFP trend had changed.[329] In other words, using NERA's terminology, the companies hypothesized that a structural break in the industry productivity trend had occurred.

310. A discussion arose during the hearing as to whether restructuring and various other changes to the electric distribution industry can be characterized as a structural break that alters the long-term industry productivity trend.[330] NERA was of the opinion that the determination on

323 Exhibit 307.01, PEG evidence, page 36.
324 Exhibit 636, CCA argument, paragraph 63.
325 See, for example, Exhibit 80.02, NERA report, page 6; Exhibit 307.01, PEG evidence, page 19; Exhibit 98.02, Carpenter evidence, page 25.
326 Exhibit 100.02, Frayer evidence, page 63.
327 Exhibit 307.01, PEG evidence, page 28, and Transcript, Volume 13, page 2494, line 6; Exhibit 631, ATCO Electric argument, paragraphs 61-62; Exhibit 632, ATCO Gas argument, paragraphs 69-70.
328 Exhibit 391.02, NERA second report, page 14.
329 Exhibit 630.01, EPCOR argument, paragraph 49; Exhibit 98.02, Carpenter evidence, page 21; Exhibit 474.02, Frayer rebuttal evidence, page 19; Exhibit 110.01, Christensen Associates evidence, pages 11-12.
330 See for example, Transcript, Volume 3, pages 477-481; Volume 4, pages 570-571; Volume 8, pages 1400-1403; Volume 11, pages 1995-1997; Volume 11, pages 2109-2113.

the subject of structural breaks lies outside the scope of regulatory proceedings and belongs to a realm of academic study. Dr. Makholm stated in testimony:

> [W]e want to stress the importance of making sure that something that would have such a severe affect on a TFP growth trend as bifurcating the study period would not come about lightly, and not come about in a contested proceeding among interested parties where the minutiae of econometrics or empirical work often go way beyond the heads of even the experts in the room. And in that respect, it was our search or objectivity and a support among people who have no interest in the outcome of the question that led us to say, in our second report, that you would want, if something so important as a structural break entered this kind of analysis, to have that support come from outside the proceeding from disinterested sources.[331]

311. With respect to the statistical tests performed by Dr. Cicchetti, NERA commented that without the underlying economic theory, these statistical tests have a very limited explanatory power. When viewed in isolation, the statistical tests simply confirm that the TFP growth in a particular period was distinctly (i.e., “statistically significant”) different from the TFP growth in other periods. The test does not, by itself, explain the reasons for such a difference and cannot prognosticate whether the TFP growth in any particular period is indicative of the changes in productivity likely to occur during the prospective PBR term.

312. The Commission agrees with NERA’s view that a deviation from reliance on the longest period of available data requires support that a structural break in the industry has occurred. The Commission also agrees that the determination of whether a structural break has occurred demands the scrutiny of academic experts, peer review and testing by parties independent of the current proceeding.

313. NERA indicated that to the best of its knowledge, the only structural breaks discussed by scholars were the World Wars, the Great Crash in 1929 and the 1970s oil price shock.[332] The companies did not point to any external studies on this issue. In the absence of any independent academic studies examining the issue of structural breaks in the electric and gas distribution industries, the Commission is not prepared to accept the proposition that the long term underlying TFP trend of the industry had changed around the mid- or late1990s as implied by the companies’ experts.[333]

314. With respect to the electric industry restructuring, the Commission observes that NERA used data only on the distribution portion of the sampled companies’ businesses.[334] In the Commission’s view, this approach sufficiently mitigates the concerns about the impact of industry restructuring on the TFP estimate. The Commission accepts NERA’s view that electric industry restructuring did not necessarily lead to a change in the rate of growth of productivity for the distribution portion of the industry.[335]

315. Furthermore, the Commission is not persuaded by the companies’ arguments that a more recent period provides a better indication of likely industry TFP during the PBR term. As further

331 Transcript, Volume 2, page 300, lines 8-22.
332 Exhibit 391.02, NERA second report, pages 15-16.
333 Exhibit 630.01, EPCOR argument, paragraph 49; Exhibit 98.02, Carpenter evidence, page 21; Exhibit 474.02, Frayer rebuttal evidence, page 19; Exhibit 110.01, Christensen Associates evidence, pages 11-12.
334 Exhibit 80.02, NERA report, page 6.
335 For example, Transcript, Volume 1, pages 109-111 (Dr. Makholm).

explained in Section 6.3.6 of this decision, because NERA used a volumetric output measure, the resulting TFP estimate is sensitive to economic recessions and upturns. In these circumstances, as PEG observed in its evidence, a company's productivity growth in one five or 10-year period may be very different from its productivity growth in the following five years, depending on what part of the business cycle the economy is in.[336] Dr. Lowry explained that the productivity of a company going into a recession (i.e., from peak to trough of a business cycle) may be very different from the productivity of the same company coming out of the recession when energy throughput is used as an output measure.[337]

316. In that regard, the Commission considers that Dr. Lowry's approach to determining the relevant time period to capture the entire business cycle in the sample period represents an improvement over the companies' approach of focusing on the most recent 10 to 15 years of data. However, PEG's method is also not entirely devoid of subjectivity, as judgement has to be applied as to what start and end points to use. For example, PEG offered that cooling degree days and the unemployment rate be used to select similar levels of a business cycle. Building on this logic, PEG recommended that recession years 2008 and 2009 be excluded from the analysis, because in this period the volumetric output indexes were extraordinarily depressed.[338] The gas companies did not agree with PEG's choice of start and end dates and submitted that this method resulted in biased and subjective estimates of TFP trends.[339] In AltaGas' view, it was vital that years 2008 and 2009 be included in the study to arrive at a balanced assessment of TFP.[340]

317. In the Commission's view, NERA's approach of using the longest time period available allows a smoothing out of the effects of variations in economic conditions on the estimate of TFP growth, without engaging in a subjective exercise of picking the start and end points of a business cycle. Notably, the CCA seemed to reach a similar conclusion and indicated that if the years 2008 and 2009 were to be included in the study, the length of a sample period would have to be considerably longer than 10 to15 years and NERA's use of the full set of 1972 to 2009 data becomes reasonable, subject to certain other reservations about NERA's analysis.[341]

318. With respect to the argument that some other jurisdictions relied on a shorter time period for estimating TFP growth, the Commission notes that in many of those cases the period for a TFP study is driven by data limitations rather than a deliberate choice of the most relevant period for productivity calculations or is the result of settlement negotiations. This is especially true in the case of PBR plans based on efficiency frontiers and benchmarking studies which require a large amount of company-specific data for the selected group of peer companies. Dr. Cicchetti and Ms. Frayer noted that their observation of the other regulators' use of a 10-year period was more in the nature of a "rule of thumb."[342] The circumstances leading to the acceptance by other regulators of a sufficient TFP time period are varied and in the Commission's view do not suggest an accepted regulatory practice. This conclusion is reinforced by the differing views on the correct time period over which to conduct a TFP study reflected in the evidence of the various experts in this proceeding.

336 Exhibit 307.01, PEG evidence, page 23 and Exhibit 569.01, PEG rebuttal evidence (corrected), pages 7-9.
337 Transcript, Volume 13, page 2503, line 9 to page 2504 line 1.
338 Exhibit 569.01, PEG rebuttal evidence (corrected), pages 7-9.
339 Exhibit 632, ATCO Gas argument, paragraph 77 and Exhibit 628, AltaGas argument, page 21.
340 Exhibit 650, AltaGas reply argument, page 18.
341 Exhibit 645, CCA reply argument, paragraph 38.
342 Transcript, Volume 11, page 2056, lines 10-15 and Volume 11, page 2115, lines 1-14.

319. In light of the above considerations, the Commission agrees with NERA's view that using the longest time period for which data are available is theoretically sound and represents the most objective basis for the TFP calculation. In the Commission's view, in the absence of any external scholarly studies pointing to a structural break in the TFP trend of the electric distribution industry, NERA's analysis based on a full 1972 to 2009 sample is the best indicator of the expected industry productivity growth during the PBR term. Moreover, such an approach eliminates the inevitable subjectivity involved in choosing a truncated time period for determining the industry TFP and mitigates the incentive to "cherry-pick" the start and end points to arrive at a desired TFP value.

320. In this respect, the Commission observes that PEG's preference for a 15-year sample period appeared to be primarily based on Dr. Lowry's personal judgement:

> Q. But what I'm trying to understand, though, Sir, the principles that you're applying in coming up with your period so that the subjectivity of picking the dates is reduced?
> A. Yes. Just based on my experience, you know, I used to think that you needed 10 years to smooth things out, and now I'm thinking more like 15. I don't know what more to say.[343]

321. The Commission recognizes that because PEG did not use a volumetric output measure, the resulting TFP may be less sensitive to the choice of start and end dates. As well, Dr. Lowry noted that the quality of data on the gas industry prior to 1996 was not good.[344] As such, the Commission acknowledges that it is uncertain whether having a longer time period for PEG's data would result in a different TFP measure. Nevertheless, in the Commission's view, PEG's approach to selecting the time period is more subjective than NERA's. Dr. Lowry acknowledged that if the Commission were to adopt his approach, the start and end dates of a sample period have to be reconsidered at the time of any PBR rebasing.[345]

6.3.3 The use of U.S. data and the sample of comparative companies in the TFP study

322. NERA's TFP study used a population of 72 U.S. electric and combination electric/gas companies. NERA noted that this population includes companies of different sizes and located in differed parts of the United States reflecting a wide diversity of geography, development and age.[346] PEG's study was based on a national sample of 34 U.S. gas distributors,[347] also with different operating characteristics.[348] In both studies, the sample size reflected the availability of reliable data for the U.S. companies in question.[349]

323. When questioned by the CCA on whether it is preferable to use a region-specific sample rather than a national sample, NERA's experts indicated that it is acceptable to base a TFP study on either all companies in an industry for which good data are available or to select a sub-sample

343 Transcript, Volume 13, page 2499, lines 5-10.
344 Transcript, Volume 13, page 2495, lines 14-16.
345 Transcript, Volume 13, page 2506, lines 7-9.
346 Exhibit 80.02, NERA report, page 4.
347 In its evidence, PEG also reported results of a subgroup of 7 Western U.S. companies (Exhibit 307.01, tables 1 and 2). However, as Dr. Lowry indicated, PEG did not base its recommendations on the Western subgroup analysis and it was included just as "another number for the Commission to use if they see fit" (Transcript, Volume 13, pages 2525-2527). Accordingly, the Commission did not discuss this part of PEG's evidence.
348 Exhibit 307.01, PEG evidence, pages 26-27.
349 Transcript, Volume 3, page 458, line 23 to page 459, line 3 and Volume 13, page 2528, lines 16-21.

if the sub-sample is large enough to provide a reliable measure of productivity growth.[350] In that regard, Dr. Makholm pointed out that NERA's previous TFP study for Alberta from 2000[351] was based on a group of companies from the Western region. However, because the number of companies remaining in the Western region had declined since that time, NERA concluded that a TFP estimate based on this smaller group would give a less reliable, consistent and robust measure of productivity growth. As a result, NERA examined a national population of companies for its TFP analysis in this proceeding.[352]

324. The UCA indicated that NERA's sample of U.S. utilities is not comparable to Alberta gas and electric utilities in many respects. For example, the UCA noted that the NERA study sample contained companies that are unlike any Alberta distribution utility in terms of geography and climatic conditions. In addition, the UCA indicated that the U.S. utilities are subject to multiple different regulatory regimes with some operating under PBR and others under cost of service regimes. Further, the UCA pointed to differences in a number of other operational characteristics such as retail sales or number of employees between the companies in NERA's sample and Alberta utilities.[353]

325. In the UCA's opinion, it is critically important that the multiple differing regulatory, operational, organization and geographical circumstances of the companies included in the NERA sample be fully understood. Accordingly, the UCA argued that the companies included in the comparative group for Alberta utilities should be (i) unbundled, (ii) have some degree of comparability, and (iii) if possible, some should have been under PBR for quite some time.[354] Given the availability of historical data (1988 to 1997) for the distribution utilities in Ontario, the UCA argued that there is simply no need to use the U.S. data.[355]

326. In response to these criticisms, NERA explained that the purpose of the TFP study is not to explain productivity levels but instead productivity growth rates. In other words, NERA's study did not examine whether one company has a greater level of output for the same level of inputs than another. Rather, NERA looked at how the ratio of outputs to inputs changes over time. As such, the unique cost features of any particular company cancel out in the process.

327. Furthermore, NERA observed that the theoretical purpose of the X factor (to which the TFP study contributes) is not to find proxies for the companies to be regulated but rather to find the long-term, underlying industry productivity growth trend that firms would face in competitive markets. As such, a focus on finding companies just like those in Alberta would not accomplish this objective. Given the generally-perceived similarity of both the legal construct for utility regulation in Canada and the United States as well as the organization of the utility industries in the two countries, NERA maintained that using the U.S. data is warranted in this case.[356] Calgary and Fortis agreed with this approach.[357]

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350 Transcript, Volume 3, page 394, line19 to page 396, line 20.
351 Evidence of Jeff D. Makholm on behalf of UtiliCorp Networks Canada on its proposed PBR plan dated September 1, 2000 (Exhibit 195.01, AUC-NERA-5(a)).
352 Exhibit 391.02, NERA second report, paragraphs 45-46.
353 Exhibit 299.02, Cronin and Motluk UCA evidence, pages 219-227.
354 Exhibit 634.02, UCA argument, paragraph 99.
355 Transcript, Volume 17, page 3219, lines 3-7 and page 3222, lines 1-16.
356 Exhibit 391.02, NERA second report, paragraphs 36-38.
357 Exhibit 629, Calgary argument, pages 23-24.

328. The other parties to this proceeding generally agreed with NERA's position on these issues. With respect to the study sample, EPCOR pointed out that the standard approach in North American PBR regulatory jurisdictions is to compare each company to the industry performance and not to specific peer groups.[358] Fortis also agreed with this approach, although Ms. Frayer expressed some concerns as to the applicability of the NERA study to Alberta companies.[359] The ATCO companies agreed with Dr. Makholm's opinion that a sample with fewer than 12 companies is too small to be representative of the industry TFP trends and supported NERA's approach of using the national population.[360]

329. Regarding the use of U.S. data, the CCA and the ATCO companies indicated that there are no suitable Canadian data available to make a reliable TFP estimate for the gas or electric distribution industries in Canada. Furthermore, even if suitable data were available, it is uncertain whether there are enough utilities in Canada to make a TFP estimate reliable given the small sample size it would be based upon.[361] Overall, the ATCO companies did not object to the use of the U.S. data, albeit subject to an adjustment for a productivity gap between the United States and Canadian economies, as further discussed in Section 6.4.2 of this decision.[362]

330. Similarly, Dr. Cicchetti on behalf of EPCOR noted that because of the differences between the United States and Alberta economies, the industry TFP trends that NERA estimated do not reflect economic conditions in Alberta. Nonetheless, Dr. Cicchetti concluded that NERA's U.S. data were a good starting point to use for the purposes of determining an X factor for EPCOR.[363] Ms. Frayer's preference was to consider relevant Canadian or Alberta utility data when available. However, in developing her recommendations for Fortis' X factor, Ms. Frayer used U.S. data and data from other jurisdictions, including the U.K., New Zealand and Australia.[364]

331. In the view of Dr. Schoech, it would be most desirable to look at the TFP growth for natural gas distribution companies that are most comparable to AltaGas in terms of their market context, in particular, the number of customers served and population density.[365] However, recognizing that there may not be historical data for utilities closely similar to AltaGas, the company's experts used broader sources of data to determine an appropriate historical estimate of TFP and to develop their proposal for the X factor. Specifically, in AltaGas' analysis, the results of the NERA's study were complemented with Statistics Canada's estimate of MFP trends in the gas distribution sector which also include water and other system utilities.[366]

332. AltaGas also took issue with PEG's study sample. First, AltaGas noted that PEG's productivity analysis was drawn from data representing less than half of the U.S. gas distribution industry. Second, in AltaGas' view, the selection of companies was biased, favouring larger service providers. And finally, AltaGas contended that it was unlikely that PEG's productivity study included any gas distributors with service territories and business contexts comparable to

358 Exhibit 630.02, EPCOR argument, paragraph 55.
359 Exhibit 633, Fortis argument, paragraph 91 and Exhibit 474.02, Frayer rebuttal evidence, pages 14-15.
360 Exhibit 631, ATCO Electric argument, paragraph 71; Exhibit 632, ATCO Gas argument, paragraph 78.
361 Exhibit 636, CCA argument, paragraph 75; Exhibit 631, ATCO Electric argument, paragraph 80; Exhibit 632, ATCO Gas argument, paragraph 89.
362 Transcript, Volume 3, page 591, line 23 to page 592, line 3.
363 Exhibit 630.02, EPCOR argument, paragraph 59.
364 Exhibit 633, Fortis argument, paragraph 96.
365 Transcript, Volume 8, page 1417, line 12 to page 1418, line 9.
366 Exhibit 628, AltaGas argument, pages 22-23.

those of the company.[367] The latter concern was also raised by Dr. Carpenter, who noted that ATCO Gas has a customer density well below the average of PEG's sample.[368]

Commission findings

333. As explained earlier in Section 6.2 of this decision, the UCA's approach to determining the X factor was based on an examination of the companies' efficiency or, in other words, whether one company has a greater level of output for the same level of inputs compared to other companies. The Commission explained that under this approach it is important to control for all the factors contributing to a firm's level of efficiency, since inadvertently leaving out an important productivity driver may invalidate the results of the study. In these circumstances, the search for companies with similar characteristics (location, size, geography, weather, consumption patterns, etc.) for the purposes of inclusion in the comparative group on which to base the productivity study becomes of paramount importance for the PBR plans based on efficiency benchmarking.

334. As set out in Section 6.2 above, the Commission does not accept the efficiency benchmarking approach for the purposes of PBR in Alberta because of the practical and theoretical problems associated with measuring efficiency levels.

335. Under the approach adopted by the Commission, the focus of the TFP study is on the industry productivity growth rate, not levels. As NERA explained, in this case the manifest differences between the companies in terms of their geographic areas and climatic conditions, operational characteristics, regulatory regime, size or any other consideration do not matter as much to the study as it only deals with the average of year to year changes in productivity growth. As such, the unique cost features of any particular company cancel out in the process.[369]

336. Indeed, the experience of Dr. Cronin and Mr. Motluk corroborates this conclusion. The UCA witnesses observed that the Ontario companies exhibited a similar productivity growth rate during the PBR term despite the inherent differences in age, past performance and investment needs.

> But what was remarkable about that performance was the near uniformity that the [local distribution companies] exhibited in engendering TFP of 1.2 percent per year. It didn't matter if they were large, medium, or small. It didn't matter if they had more aged infrastructure. It didn't matter if they were high growth or low growth. It didn't matter if they were high capital additions or low capital additions. What they did was they found a way to operate under the PBR for that period of time. This was again confirmed under the second variable [productivity factor] PBR in the first half of this decade.[370]

337. The Commission agrees with NERA's characterization that the TFP estimate that informs the X factor is supposed to reflect industry growth trends, not the trends in Alberta alone or among a group of companies with similar operations and cost levels to those in Alberta.[371]

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[367] Exhibit 628, AltaGas argument, pages 23-24.
[368] Exhibit 472.02, Carpenter rebuttal evidence, page 80.
[369] Exhibit 391.02, NERA second report, paragraph 37.
[370] Transcript, Volume 17, page 3183, line16 to page 3185, line 4; and see also at Transcript, Volume 17, page 3192, lines 16-20.
[371] Exhibit 391.02, NERA second report, paragraph 38.

338. In these circumstances, it is the Commission's view that when it comes to the sample size and the use of U.S. data in TFP studies, the relevant question to ask is not whether the companies in the sample are similar to the Alberta utilities, but: (i) whether the sample in the TFP study is reflective of the productivity trend in the U.S. power distribution industry, and (ii) whether the U.S. industry TFP trend represents a reasonable productivity trend estimate for the Alberta companies.

339. Regarding the first question, the Commission agrees with NERA, ATCO Electric and the CCA that a TFP study can be based on either all companies in the industry for which good data are available or on a sample of companies as long as this sample can provide a reliable, consistent and robust measure of industry productivity growth. The Commission observes that both NERA and PEG used data availability and data consistency as the primary criteria for including a particular company in their study sample.[372] Accordingly, the Commission does not consider that NERA's and PEG's sample selection is biased in any respect.

340. Furthermore, NERA pointed out that a study sample has to be large enough to provide robust estimates and did not recommend using a sample with fewer than 12 companies.[373] As noted earlier in this section, NERA's sample consisted of 72 companies of different sizes, reflecting a wide diversity of geography, development and age.[374] As well, PEG's study was based on a sample of 34 U.S. gas distributors.[375] The Commission considers these samples to be large enough and diversified enough to produce a TFP estimate that is reflective of the overall industry productivity growth.

341. With regard to the second question, the Commission notes that the need to use U.S. data in establishing productivity targets for Alberta regulated companies arose because of the lack of uniform and standardized data for Canadian electric and gas distribution utilities. As NERA and PEG pointed out, unlike in the United States, there is no Canadian central repository of public data due to the lack of standardized accounting across provinces with respect to utility operating reports.[376] Because of this data problem, regulators in Canada have used U.S. data. For example, the Ontario Energy Board, in several decisions, used U.S. data in establishing its PBR plans.[377]

342. Mindful of the existing Canadian data limitations, the Commission agrees with NERA, the CCA, the ATCO companies and EPCOR that given the generally perceived similarity of both the utility regulatory systems in Canada and the United States, as well as the organization of the utility industries in the two countries, the U.S. power distribution industry TFP growth trend is a reasonable starting point in establishing a productivity estimate for the Alberta companies.[378] This issue is further discussed in Section 6.4.2 of this decision dealing with the proposal for a productivity gap adjustment.

343. In light of the above considerations, the Commission finds NERA's and PEG's TFP study samples of 72 and 34 U.S. companies, respectively, to be acceptable, subject to the

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[372] Transcript, Volume 3, page 458, line 23 to page 459, line 3 and Volume 13, page 2528, lines 16-21.
[373] Transcript, Volume 3, page 395, lines 12-24.
[374] Exhibit 80.02, NERA report, page 4.
[375] Exhibit 307.01, PEG evidence, page 26.
[376] Transcript, Volume 2, page 290, lines 22-24; Exhibit 307.01, PEG evidence, page 25.
[377] Exhibit 195.01, AUC-NERA-7 and Exhibit 634.02, UCA argument, paragraphs 110-111.
[378] Exhibit 391.02, NERA second report, paragraph 36; Exhibit 636, CCA argument, paragraph 75; Exhibit 631, ATCO Electric argument, paragraph 80; Exhibit 632, ATCO Gas argument, paragraph 89; Exhibit 630.02, EPCOR argument, paragraph 59.

issues discussed below, as the starting point for a TFP analysis applicable to Alberta distribution utilities.

6.3.4 Importance of publicly available data and transparent methodology

344. In its September 8, 2010 letter to the parties, the Commission included the use of publicly available data and a transparent methodology as part of the requirements for NERA to meet in respect of its TFP study contributing to a PBR plan.[379]

345. NERA agreed with these requirements and pointed out that the extent to which PBR regulation transmits incentives to company management is critically dependent on the transparency, stability and objectivity of the formula that governs price movements between rate cases. In NERA's view, creating an index number for relative industry TFP with those attributes requires a high-quality transparent and uniform source of data that is readily available to the parties of regulatory proceedings. For this purpose, NERA used the data collected by the Federal Energy Regulatory Commission (FERC) for electric and combination electric/gas utilities on its Form 1 and other publicly available sources.[380] In NERA's view, the FERC Form 1 data are the only data that satisfy the criteria of transparency and objectivity for a large number of industry participants.[381]

346. NERA also expressed its opinion that transparency is the essential component of any analysis for the purpose of PBR plans. To this end, for each step of its analysis NERA documented the methodology and the data used to measure TFP. In addition, NERA's calculations and working papers, including any adjustments to the electronic dataset (such as for missing observations or rare but evident data anomalies) were made available for inspection and assessment by other parties.

347. All parties confirmed the importance of relying on publicly available data and transparent methodologies for the purpose of the TFP studies used in regulatory proceedings in order to make such studies objective and neutral.[382] In this respect, while no party questioned the transparency of NERA's methodology and the availability of FERC Form 1 data, parties to this proceeding took issue with PEG's productivity study over issues of objectivity and transparency.

348. With respect to transparency, ATCO Gas and AltaGas pointed out that PEG's study relied on a proprietary data which could not be fully tested in a public forum. Furthermore, these companies noted that even after examining PEG's working papers (made available under a confidential process), it was still unclear where individual data came from, as limited details were provided on the methods and sources used in the study.[383] Because of this lack of transparency in PEG's data and calculations, Dr. Carpenter indicated that he was not able to fully evaluate and replicate the results of PEG's TFP study.[384]

379 Exhibit 71.
380 Exhibit 80.02, NERA report, pages 3-4 and Transcript, Volume 1, pages 55-57.
381 Transcript, Volume 1, page 56, lines 6-14.
382 Exhibit 630.02, EPCOR argument, paragraph 57; Exhibit 631, ATCO Electric argument, paragraph 73; Exhibit 632, ATCO Gas argument, paragraph 80; Exhibit 628, AltaGas argument, pages 24-25; Exhibit 645, CCA reply argument, paragraph 45.
383 Exhibit 476.01, Carpenter rebuttal evidence, pages 74-77 and Exhibit 477, Christensen Associates rebuttal evidence, paragraph 36.
384 Exhibit 476.01, Carpenter rebuttal evidence, page 77 and Transcript, Volume 6, page 1007, lines 7-15.

349. On the same subject, NERA observed that since there is no federal collection of universal and consistent data on the U.S. gas distributors similar to the FERC data set for the electric industry, statistical data from individual states must be used. Because of the varying data reporting requirements in different states, NERA cautioned that compilation of data from varying sources may not be consistent.[385]

350. The gas companies' concern regarding the lack of objectivity in PEG's study primarily related to the econometric model that Dr. Lowry and his colleagues used in addition to the index approach for estimating TFP. In particular, PEG regressed the TFP index for the 32 gas companies in its sample against the number of gas distribution customers, the number of electricity customers (for companies that provide both gas and electric service), the line miles and a time trend variable. Applying the obtained coefficients to the projected variables for Alberta gas companies, PEG came up with a TFP estimate customized for business conditions in Alberta.[386]

351. With regard to this method of TFP calculation, ATCO Gas' and AltaGas' experts pointed to a number of issues in the set-up of PEG's econometric model relating to the choice of explanatory variables, model specification, the interpretation of results, the presence of heteroskedasticity, etc.[387] NERA observed that an econometric estimation of TFP growth is unavoidably based on many judgments that are difficult for non-specialists to understand. In NERA's view, such econometric analyses are more suitable for the purpose of peer-reviewed scholarly research and not for setting the level of consumer prices in a PBR plan.[388]

352. To allay concerns about the use of proprietary data, PEG recalculated the TFP growth of the sample of gas distributors employing data that are entirely in the public domain. This resulted in a modest decrease in PEG's TFP number, from 1.32 per cent to 1.19 per cent. At the same time, PEG noted that although most of its data can be independently gathered from the public sources, it chose to purchase them from respected commercial vendors because of the higher quality and value added services that they provide.[389] In that regard, Dr. Lowry proposed that the value added by the commercial vendors in gathering and processing the data is well worth the restriction of a confidentiality agreement to permit their use in a regulatory proceeding.[390]

Commission findings

353. Because the parameters of the PBR formula will be used to determine customer rates in a contested regulatory process and those rates will be in place for a number of years, the significance of the objectivity, consistency, and transparency of the TFP analysis to be employed in calculating the X factor cannot be understated.[391] In this respect, the Commission observes that having extensively scrutinized and tested NERA's study, the companies were satisfied that

[385] Transcript, Volume 1, page 52, lines 16-22.
[386] Exhibit 307.01, PEG evidence, page 33.
[387] Exhibit 476.01, Carpenter rebuttal evidence, pages 83-84 and Exhibit 477, Christensen Associates rebuttal evidence, paragraph 46.
[388] Exhibit 391.02, NERA second report, paragraph 99.
[389] Exhibit 478.01, PEG rebuttal, pages 20-21.
[390] Transcript, Volume 13, pages 2456-2459.
[391] Exhibit 391.02, NERA second report, paragraphs 95-96 and Exhibit 476.01, Carpenter rebuttal evidence, page 29.

NERA's TFP analysis complies with these criteria.[392] The Commission agrees. As Dr. Cicchetti commented on this issue:

> So my conclusion is NERA was objective and neutral as required to be by this Commission. It's also transparent in that you can see where the information came from. You can actually go back to the raw information to see if NERA made any mistakes in building the data set together and the like. And in that fashion I think they did exactly what the Commission asked and therefore I would use it as I did in my starting point.[393]

354. With respect to PEG's study, the Commission shares the gas companies' concerns that the TFP analysis of Dr. Lowry and his colleagues was not fully transparent and conducive to the detailed scrutiny by other experts or by the Commission.

355. While there is nothing inherently wrong with using proprietary data in regulatory proceedings, procedural fairness requires that parties must be provided with the opportunity of a fair hearing in which each party is given the opportunity to respond to the evidence against its position. This requirement clearly requires parties and the Commission to be able to fully understand, test and respond to the evidence filed in a proceeding. Further, the Commission has the obligation to provide reasons for its decisions. It can only do so if it is able to fully understand, test and analyze the evidence filed before it. Accordingly, fully transparent information is always preferable to information that requires the filing of motions for protection of confidential information and the execution of confidentiality agreements. It is also problematic if, in order to fully comprehend the confidential information, further explanations must be provided on the procedures used, assumptions made, judgment exercised and data adjustments made that produced the confidential evidence. In addition, as NERA observed, the problem with data that are not publicly available is that the research cannot be replicated. As well, there is a concern that such data will not be available at all or that only the original provider using the same assumptions, methodology and adjustments could be engaged to provide a consistent analysis when the parameters of the PBR regime are to be reset.[394]

356. The Commission agrees that it is highly desirable that any TFP analysis can be replicated by all willing parties to the proceeding. As Dr. Carpenter explained, until one has managed to replicate a piece of analysis, it is not possible to look for errors, adjust assumptions, and test for sensitivities.[395] In addition, as NERA pointed out, if Dr. Lowry and his colleagues at PEG are the only persons who are able to repeat the TFP analysis, the success of any future PBR plans will depend on PEG's participation.[396] For all of the above reasons, the Commission confirms its preference for a TFP study that relies on publicly available data.

357. The Commission's main concern with PEG's study relates to the overall lack of transparency with respect to data processing. The Commission accepts that because there is no central repository for data on the gas distribution industry, any researcher of this subject would be compelled to combine information from different sources, thus facing a problem of data consistency and uniformity.[397] However, to the extent that PEG compiled its dataset from a

[392] Exhibit 632, ATCO Gas argument, paragraph 83; Exhibit 631, ATCO Electric argument, paragraph 76; Exhibit 630.02, EPCOR argument, paragraph 57; Exhibit 628, AltaGas argument, page 24.
[393] Transcript, Volume 11, page 2017, lines 10-17.
[394] Exhibit 391.02, NERA second report, paragraph 98.
[395] Exhibit 476.01, Carpenter rebuttal evidence, page 82.
[396] Transcript, Volume 1, page 56, lines 15-23.
[397] Transcript, Volume 1, page 56, lines 6-14 and Volume 13, page 2467, lines 2-7.

number of sources (publicly available or not), it is of vital importance that all the steps and any adjustments to the data be clearly documented and explained. This would allow other experts to verify the accuracy of the data. As well, computation of the TFP estimate must be clearly explained. In this way, other parties to the proceeding can test and verify the calculations and, if necessary, replicate them in future proceedings. PEG's study did not satisfy these requirements.

358. For example, Dr. Lowry explained that PEG examined the dataset obtained from a commercial vendor and when necessary, made adjustments to the data to correct for any obvious anomalies:

> [...] not only does my staff do an initial screening and look for oddities to correct, to look for corrections, go make sure that that's what the form really said; but then it comes to me, and that's the final step is that I will go through very carefully and meticulously all the data and see if it squares with my expectations. And there will usually be 10 or 15 observations that need to be changed based on my second screening of the data.[398]

359. The Commission accepts that sometimes it may be necessary to adjust the raw data and in fact, NERA had to adjust its data as well. However, as Dr. Carpenter explained in his evidence, PEG did not clearly outline the adjustments it made.[399] In contrast, NERA made available for inspection and assessment by other parties any adjustments to the electronic dataset that it made as an integral part of its report.[400]

360. The importance of publicly available data and transparent methodology is demonstrated by the extent to which parties to this proceeding relied on NERA's working papers for developing their recommendations. For example, Dr. Cicchetti was able to estimate partial factor productivity (PFP) for EPCOR relying entirely on NERA's data.[401] As well, Dr. Cicchetti performed a number of statistical tests on productivity using company-level panel data.[402] Dr. Lowry, after scrutinizing NERA's working papers, suggested a number of corrections to NERA's study and was able to immediately quantify the impact of his recommendations on NERA's TFP estimate.[403]

361. If the parties had been using PEG's data, they would not have been able to engage in this type of detailed analysis without first executing a confidentiality agreement and working with PEG to understand all adjustments that were made to the vendor's data. For example, Dr. Carpenter pointed out that the output file that PEG provided included only summary results and did not provide the data for individual companies. As well, Dr. Carpenter pointed to the fact that PEG's computer code was written for a software package that was not commercially available.[404]

362. With respect to PEG's econometric model for TFP, the Commission agrees with NERA's explanation that the outcome of any regression model is highly dependent on the choice of explanatory variables, which represents the subjective judgment of the person conducting the analysis. As NERA explained:

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398 Transcript, Volume 13, page 2460, lines 4-12.
399 Exhibit 472.02, Carpenter rebuttal evidence, page 28.
400 Exhibit 80.02, NERA report, Appendix II.
401 Exhibit 103.05, Cicchetti evidence, pages 22-23.
402 Exhibit 473.07, Cicchetti rebuttal evidence, page 9.
403 Exhibit 478, PEG rebuttal evidence, Table 3 on page 12.
404 Exhibit 476.01, Carpenter rebuttal evidence, pages 74 and 77.

> DR. MAKHOLM: I was the first one to do that. I did the first decomposition of electric utility TFP numbers anywhere, and it's my thesis. I've done that. And if you go to the back of that, you'll see page after page after page of coefficients that depend on the specification that I chose, the number of things I decided to measure, the kind of dummy variables that I would use.
>
> And the results of those decompositions, as I call them, were dependent on my particular specification and what I judged to be useful at the time. I put it that -- to this group and to this Commission that those decisions of mine, which were useful for doing my thesis work, could have been done differently, and they could have changed the result of how we would predict the TFP growth should be for any region or size of company or any arbitrary company out there, and it could have been a lot different.[405]

363. Dr. Lowry also agreed that the exclusion of relevant variables biases the estimators and noted that PEG's analysis included "as many variables that matter as we can."[406] For example, PEG offered that a company's productivity growth is a function of the number of customers (gas and electric, if applicable), line miles and time.[407] However, in AltaGas' opinion, the model should also have included the volume of gas delivered, as variation in usage per customer also affects productivity.[408] Therefore, the Commission agrees with NERA's conclusion that econometric models are prone to the criticism of being less objective and too complex for the purposes of PBR plans.

364. In light of the above considerations, the Commission agrees with NERA, ATCO Gas and AltaGas that the lack of publicly available data and transparent methodology represent major drawbacks to the use of PEG's productivity analysis. In contrast, as noted earlier in this section, the Commission agrees with the companies that NERA's TFP study was transparent and objective.

6.3.5 Applicability of NERA's TFP study to Alberta gas distribution companies

365. The data used in NERA's study are for the distribution portion of the electric companies, whether standalone or combination electric/gas companies according to FERC Form 1. NERA indicated that its study did not include data for standalone gas companies, since it was not aware of a readily available data source that would permit a comparably transparent TFP study for standalone gas companies.[409]

366. In NERA's view, the productivity of gas and electricity companies is similar. For example, NERA observed that both electricity and natural gas distribution are highly capital intensive. Additionally, in some instances the electricity and gas distribution facilities share the same support structure.[410] During the hearing, Dr. Makholm noted that based on his personal knowledge of operations of gas and electric distribution industries, the institutional framework and regulatory and business requirements for the two sectors are quite similar. Accordingly,

405 Transcript, Volume 3, pages 475-476.
406 Transcript, Volume 13, page 2548, lines 14-22.
407 Exhibit 307.01, PEG evidence, page 33.
408 Exhibit 477, Christensen Associates rebuttal evidence, paragraph 46.
409 Exhibit 80.02, NERA report, pages 6-7.
410 Exhibit 80.02, NERA report, pages 6-7.

Dr. Makholm expressed his opinion that it is not necessary to differentiate the productivity growth for gas and electric distribution industries.[411]

367. Furthermore, NERA observed that according to data from Statistics Canada, TFP growth during the period 1972 to 2006 for Canadian electric power generation, transmission and distribution companies was 0.28 per cent while for natural gas distribution, water and other systems TFP growth was 0.21 per cent, using gross output as the output measure. Using value added as the measure of output, the numbers are 0.37 per cent for electric power generation, transmission and distribution companies and 0.34 per cent for natural gas distribution, water and other systems.[412] At the same time, Dr. Makholm cautioned that NERA's observation of the Statistics Canada indexes was merely a "relatively casual view" of a data source that NERA did not use in its study.[413] PEG, AltaGas and the ATCO companies also indicated that Statistics Canada's MFP indexes were subject to a number of reporting difficulties, as further discussed in Section 6.3.7 below.[414]

368. In light of the above considerations, NERA expressed its opinion that a specialized TFP study for gas distribution companies would not be a useful part of Alberta's PBR initiative, given the lack of uniform and objective data for a broad sample of gas companies that such a study would require to be a part of a transparent and objective PBR plan. Based on its familiarity with electricity and gas distribution and transmission businesses from a regulatory perspective, NERA concluded that a robust TFP study using FERC Form 1 data is a useful component of a PBR plan that applies to both the electricity and gas companies in Alberta.[415]

369. ATCO Gas and AltaGas noted that it would be preferable to base the X factor for gas companies on a study that measured TFP growth for the gas industry, if a study of sufficient transparency and quality were available. However, because the two gas companies rejected PEG's productivity study, they noted that no such study was available in this proceeding.[416]

370. In these circumstances, ATCO Gas expert Dr. Carpenter observed that in the absence of any compelling reason to distinguish between electric and gas companies, and having regard for the Statistics Canada figures that NERA cited in its report, it is reasonable to assume that the same TFP is appropriate for gas and electric utilities in Alberta.[417] Similarly, AltaGas noted that NERA's report, along with the examination of Statistics Canada MFP indexes, provides some evidence useful for estimating the TFP growth rate of Canadian gas distribution companies.[418]

371. In a similar vein, the CCA noted that since the gas and electric power distribution businesses have similarities (such as a gradual growth in rate base and the importance of customers as a cost driver), TFP research from one industry could be used to set a productivity estimate for firms in the other industry if data for both industries were unavailable. However, the CCA maintained that this was not the case in the present proceeding. In the CCA's view, PEG's analysis on U.S. gas distribution companies is suitable for the purpose of setting establishing a

[411] Transcript, Volume 1, pages 49-51.
[412] Exhibit 80.02, NERA report, page 7.
[413] Transcript, Volume 1, page 47, lines 4-6.
[414] Exhibit 307.01, PEG evidence, pages 41-43; Exhibit 99.01, Carpenter evidence, page 26; Exhibit 110.01, Christensen Associates evidence, paragraphs 43-44.
[415] Exhibit 80.02, NERA report, pages 4-5.
[416] Exhibit 632, ATCO Gas argument, pages 27-28 and Exhibit 628, AltaGas argument, page 25.
[417] Exhibit 99.01, Carpenter evidence, page 31.
[418] Exhibit 628, AltaGas argument, page 25.

TFP for Alberta gas utilities. In addition, the CCA noted that other studies of the TFP trends of Canadian gas distributors, prepared for disinterested parties such as the Ontario Energy Board and the Gaz Métro Task Force, could also be useful for the purpose of setting a gas distribution company TFP.[419] Calgary agreed that with the inclusion of PEG's TFP analysis, there are data on the record for both electric and gas companies and that the Commission's determination on TFP should reflect a range which includes both analyses.[420]

372. The UCA submitted that the range of its proposed X factor menu accommodates the TFP results of both NERA and PEG. Accordingly, the UCA argued that its X factor menu provides appropriate X factor choices for both electric and gas companies.[421]

Commission findings

373. Based on the evidence in this proceeding, and because of the similarities in the institutional framework, business environment and regulatory requirements between the gas and electric distribution industries, the Commission finds that TFP research from one industry can be used to estimate productivity growth for firms in the other industry when transparent and robust data for both industries are not available.

374. However, parties could not agree on whether the TFP estimates from PEG's study and various other studies on the productivity trends of Canadian and the U.S. gas distributors used by other regulators, as well as Statistics Canada's MFP indexes, represent a superior indicator of TFP for gas distribution companies as compared to the TFP estimate from NERA's study of the electric distribution industry.

375. As set out in Section 6.3.7 of this decision, because the Statistics Canada MFP indexes include power generation and transmission in the electric sector and water systems in the natural gas sector, these indexes are not suitable for estimating the TFP for distribution companies. With respect to the TFP studies of Canadian gas distributors prepared for other regulators (such as the Ontario Energy Board and the Gaz Métro Task Force) that PEG discussed, the Commission considers that while this productivity research can provide a useful reference for determining the general reasonableness and direction of a productivity estimate for the gas distribution companies, these studies cannot be viewed as substitutes for NERA's TFP study.

376. In particular, PEG referenced the 1.07 per cent TFP estimate for Enbridge Gas Distribution and the 1.65 per cent TFP estimate for Union Gas over the period 2006 to 2010. PEG also referred to the 1.66 per cent average annual TFP growth of Gaz Métro over the period 2000 to 2009.[422] However, the Commission observes that these TFP estimates are company-specific (i.e., these studies measure each company's own historical productivity growth and not the TFP growth of the industry).[423] Relying on these TFP estimates is not consistent with the Commission's preferred approach to determining the X factor that is based on the average long term productivity growth of the industry, as set out in Section 6.2 above. As NERA explained, the theory behind this approach dictates that the purpose of a TFP study is to estimate the long-

[419] Exhibit 636, CCA argument, paragraph 73.
[420] Exhibit 629, Calgary argument, page 24.
[421] Exhibit 634.02, UCA argument, paragraph 106.
[422] Exhibit 307.01, PEG evidence, pages 40-41.
[423] These reports were filed as Exhibit 376.03 (Gaz Métro) and Exhibit 376.04 (Union Gas Ltd. and Enbridge Gas Distribution Inc.).

term productivity growth of the industry, not the productivity growth of any particular company.[424]

377. PEG also referenced two TFP estimates with respect to the U.S. gas distribution industry. The first study found a TFP estimate of 1.18 per cent for the U.S. gas distribution industry over the period of 1999 to 2008, and the second study reported a TFP of 1.61 per cent over the period of 1994 to 2004.[425] In the Commission's view, differences in employed sample periods, input and output measures, as well as methodologies (e.g., indexing vs. econometric estimates), do not allow for a direct comparison of these numbers with NERA's TFP estimate.

378. Accordingly, the Commission finds that, in the absence of superior TFP data for the gas distribution industry, NERA's TFP study is an acceptable starting point for determining a productivity estimate for Alberta gas distribution companies.

6.3.6 Output measure in the TFP study

379. As set out in Section 6.3.1 above, productivity growth is specified as the difference between the growth rates of a firm's physical outputs and physical inputs.[426] Accordingly, the choice of an output measure directly affects the estimated TFP growth.

380. NERA indicated that its practice, both in this proceeding and in previous TFP growth analyses that it has undertaken, has been to use the sales volume, measured in kilowatt hours (kWh) as the measure of output. NERA recognized that it is possible to specify two or more outputs (such as kWh or numbers of customers) into a single output for measuring TFP. However, NERA stated its preference for kWh sales output measure, as the most representative of the nature of a company, the size of its system, and its revenues.[427]

381. At the same time, NERA accepted that this measure is not perfect and indicated that for the energy delivery business where much of the cost is tied up in long-lived capital, there are trade-offs in using one measure of output or another. For example, NERA pointed out that in a recession or in response to a price shock, kWh sales may decline with a distribution system that is otherwise unchanged, thereby seeming to show a decline in productivity growth. In that regard, NERA explained that its preference has always been to use kWh with the longest time series available so as to dampen the effects of the short-term or cyclical patterns that would most influence kWh sales as a measure of output.[428]

382. According to the CCA's experts, the correct output specification in a TFP study depends on the nature of the PBR plan. Specifically, PEG contended that volumetric output measures, such as the kWh sales used by NERA in its TFP study, are not correct in the context of revenue-per-customer cap plans. To arrive at this conclusion, Dr. Lowry of PEG showed that, if one accepts the belief that the costs of gas distributors are chiefly driven by the growth in the number of customers served, the mathematical logic of Divisia indexes dictates that the number of

424 Exhibit 391.02, NERA second report, paragraph 38.
425 Exhibit 307.01, PEG report, page 40 and Exhibit 366.04.
426 Exhibit 80.02, NERA report, page 5.
427 Exhibit 391.02, NERA second report, paragraph 47.
428 Exhibit 391.02, NERA second report, paragraph 47.

customers represents a relevant output measure to use in determining TFP as part of a PBR plan based on a revenue-per-customer cap.[429]

383. During the hearing, Dr. Lowry also explained that since under a revenue-per-customer cap plan, a company's revenues are driven by customer growth and are largely insensitive to the amount of energy sold, the number of customers is the relevant output measure to use for TFP studies used in a revenue-per-customer cap PBR plan. In contrast, under a price cap plan, a change in the amount of energy sold has an immediate effect on a company's revenues, and thus the use of a volumetric output measure is justified.[430] Accordingly, the CCA argued that output measures that place a heavy weight on volumetric and other usage should be used to determine the output index for TFP studies used in the context of a price cap PBR plan, while the number of customers should be used to determine the output index for TFP studies used in the context of a revenue-per-customer cap PBR plan.[431] NERA agreed with this logic.[432]

384. Furthermore, Dr. Lowry observed that in the presence of declining use per customer, a gas TFP study based on a volumetric output index would produce a lower productivity growth estimate compared to using the number of customers as an output measure.[433] Consequently, using a volumetric output measure in this instance would result in a TFP estimate and an X factor that are too low, lower than if the correct customer output measure had been used. This is because when usage per customer is falling, the rate of growth of customers will be greater than the rate of growth of energy transported. Therefore, the TFP growth rate, which is determined by subtracting the rate of growth of inputs from the rate of growth of outputs, will be greater when the correct customer output measure is used rather than the incorrect volumetric output measure.

385. In a similar vein, Mr. Johnson on behalf of Calgary noted that in the case of a gas company with declining use per customer, it is likely that under a price cap approach the I-X component would have to be higher than if it was applied to a revenue cap.[434] That is, if one assumes that the I factor remains unchanged, Mr. Johnson appeared to suggest that for a company experiencing the declining use per customer, the X factor will be lower under a price cap plan as compared to a revenue cap plan in order to generate the same revenue stream.

386. AltaGas' expert, Dr. Schoech, generally agreed with Dr. Lowry that in the presence of declining use per customer for gas distribution companies, the use of a volumetric output measure would result in a lower TFP growth rate than is reflective of actual productivity growth and some adjustment would be necessary to account for this fact if the TFP study were to be used for the gas distribution companies.[435] Since Dr. Schoech expressed his preference that the output measure should include both volumes and customers, he indicated that any adjustment to an X factor for a price cap to determine an X factor for a revenue-per-customer cap must apply only to the portion of the revenue requirement generated through the volumetric charges.[436]

429 Exhibit 307.01, PEG evidence, pages 16-17; Exhibit 610.03, Attachment to CCA undertaking; Exhibit 645, CCA reply argument, paragraphs 89-91.
430 Transcript, Volume 14, page 2871, line 25 to page 2872, line 11.
431 Exhibit 636, CCA argument, paragraph 113.
432 Exhibit 273.03, CCA-NERA-2(e).
433 Transcript, Volume 14, page 2872, line 20 to page 2873, line 4.
434 Transcript, Volume 15, page 2926, line 23 to page 2927, line 8.
435 Transcript, Volume 8, page 1528, lines 12-17 and page 153, line 23 to page 1534, line 7.
436 Transcript, Volume 9, pages 1714-1715.

387. At the same time, Dr. Schoech pointed out that because both the NERA study and the Statistics Canada MFP measures base their output only on volumes, and not on both volumes and customers, the baseline for making this type of adjustment was not available.[437] Consequently, since the number of customers variable was not available for neither NERA's nor Statistics Canada's studies, AltaGas submitted that there is no basis for making an adjustment to the X factor to account for declining usage per customer.[438]

388. Similarly, Dr. Carpenter on behalf of the ATCO companies generally acknowledged that in the presence of declining use per customer, a volumetric output index employed in a gas utility TFP study produces a lower gas TFP growth rate compared to an output measure based on the number of customers.[439] However, Dr. Carpenter did not accept PEG's premise that the number of customers is a primary driver of the gas companies' costs.[440] With regard to the relevant output measure for a gas TFP study, Dr. Carpenter concluded that it is unclear whether the output index should be based on the number of customers, energy delivered, or a combination of the two.[441] Nevertheless, based on his examination of the record of this proceeding, Dr. Carpenter concluded that "the NERA output index is the best we have."[442]

389. ATCO Gas did not agree with Dr. Lowry's logic and submitted that the way in which TFP is measured should not depend on the use of the resulting estimate. As such, ATCO Gas argued that the determination of whether the TFP estimate should be made using the number of customers as the output measure or energy delivered as the output measure should not depend on what use is to be made of the resulting estimate.[443]

390. The experts of the other electric companies expressed some concerns with NERA's use of kWh as the measure of output. Dr. Cicchetti noted that any TFP study for electricity distribution should reflect the fact that activities associated with customer numbers are critical to the services that distributors provide, for example extending distribution networks to serve new customers, meter reading, service calls, etc. Accordingly, in Dr. Cicchetti's view, an output measure in a TFP study should include the number (and perhaps location) of customers that the companies serve.[444] A similar argument was put forward by IPCAA's and the UCA's experts who noted that using kWh as the only output measure does not accurately reflect the outputs the distribution company is providing.[445] In this case, Dr. Cicchetti explained that because in the electric distribution industry the usage per customer is growing, not declining, the rate of growth of customers will be smaller than the rate of growth of energy throughput.[446] Accordingly, Dr. Cicchetti's, IPCAA's and the UCA' recommendations on output measure would result in a lower TFP and a lower X for electric companies.

391. Ms. Frayer noted that the use of a single output measure will make the resulting TFP estimate more volatile, as demonstrated by the year-to-year results in NERA's report. In

437 Transcript, Volume 8, page 1534, lines 9-17.
438 Exhibit 628, AltaGas argument, page 36.
439 Transcript, Volume 6, page 979, lines 20-24.
440 Transcript, Volume 6, page 983, lines 3-11.
441 Exhibit 472.02, Carpenter rebuttal evidence, page 32.
442 Transcript, Volume 6, page 981, lines 1-2.
443 Exhibit 632.01, ATCO Gas argument, pages 21-27.
444 Exhibit 103.05, Cicchetti evidence, pages 13-14.
445 Exhibit 306.01, Vidya Knowledge Systems evidence, pages 4-5; Exhibit 299.02, Cronin and Motluk UCA evidence, page 235.
446 Exhibit 103.05, Cicchetti evidence, page 14.

Ms. Frayer's view, using more than one output measure would smooth out this volatility and produce a more stable output index that is more consistent with the multi-dimensional service that the distribution companies provide.[447]

Commission findings

392. The Commission agrees with the experts in this proceeding that each possible output measure (for example, energy sales, number of customers, line miles, peak usage, etc.) or combination thereof has its own merits and disadvantages.[448] However, the Commission agrees with NERA's and PEG's view that when selecting a particular output measure, it must be matched to the type (price cap or revenue-per-customer cap) of a PBR plan.[449]

393. As discussed in Section 4 of this decision, the Commission recognizes that the rate designs of the gas distribution companies do not entirely reflect their cost drivers. While a large proportion of gas distributors' costs are fixed, a significant portion of these costs is recovered through variable charges. Also, as discussed in Section 4, both AltaGas and ATCO Gas are experiencing a declining use per customer. In these circumstances, a decline in use per customer would lead to a decrease in the companies' revenues that would not be offset by a decrease in costs. As a result of these considerations, the Commission is approving PBR plans in the form of a revenue-per-customer cap for ATCO Gas and AltaGas.

394. The experts in this proceeding explained that by focusing on revenue per customer as opposed to prices per unit of gas delivered, the revenue-per-customer cap plan effectively shields the revenue of gas companies from variations in energy use per customer.[450] In these circumstances, Dr. Schoech[451] on behalf of AltaGas and Dr. Cicchetti[452] on behalf of EPCOR acknowledged that the number of customers, not the volumes sold, becomes the driver of a company's revenues.[453] The Commission agrees with Dr. Lowry and his colleagues at PEG that for revenue-per-customer cap plans, the number of customers, rather than a volumetric output measure, is the correct output measure for a TFP study.

395. Using similar logic, the Commission agrees with Dr. Lowry that output measures that place a heavy weight on volumetric and other usage measures should be used for TFP studies that are part of a price cap PBR plan.[454] Therefore, the Commission considers that kWh sold output measure used by NERA in its TFP study remains an acceptable output measure to use for the purpose of the price cap PBR plans approved for ATCO Electric, Fortis and EPCOR.

396. The Commission acknowledges the concerns of Fortis, EPCOR, IPCAA and the UCA that a single output measure such as kWh may not capture all of the outputs that an electric distribution company provides. However, as the Commission observed earlier in this section, a consensus on the best measures to use has not been reached, with different experts offering different measures. For example, Dr. Cronin noted that the most relevant output measure is the

[447] Exhibit 474.02, Frayer rebuttal evidence, page 16.
[448] Exhibit 391.02, NERA second report, paragraph 47.
[449] Exhibit 307.01, PEG evidence, page 12; Exhibit 273.03, CCA-NERA-2(e).
[450] Exhibit 100.02, Frayer evidence, page 23; Transcript, Volume 6, page 986, lines 9-13; Transcript, Volume 14, pages 2871-2872.
[451] Transcript, Volume 9, pages 1714-1715.
[452] Transcript, Volume 11, page 2070, lines 3-6.
[453] Transcript, Volume 9, page 1714, lines 8-18.
[454] Transcript, Volume 14, 2872 lines 4-7.

number of customers.[455] In Dr. Cicchetti's[456] and Ms. Frayer's[457] view, both megawatt hours and the number of customers have to be considered. Dr. Carpenter concluded that it is unclear whether the output measure should be based on the number of customers, energy delivered, or a combination of the two.[458] Dr. Lowry preferred energy delivered.[459] In light of this uncertainty, the Commission is not persuaded that NERA's output measure of kWh sold is an inferior output measure compared to the variety of alternatives proposed.

397. With respect to Ms. Frayer's concern that the use of a single output measure based on energy volumes will make the resulting TFP estimate more volatile, the Commission agrees with NERA that using kWh with the longest time series available will mitigate such volatility.[460] Overall, the Commission agrees with Dr. Carpenter's view that NERA's output index measuring kWh sold is an acceptable measure to use for the purpose of calculating TFP growth for electric distribution companies.

6.3.7 Other productivity indexes

398. In addition to the two TFP studies performed by NERA and PEG, ATCO's, Fortis' and AltaGas' experts relied on the various MFP indexes published by Statistics Canada and academic publications examining productivity in different sectors of the U.S. and Canadian economies. In developing their productivity target recommendations, the experts of Fortis and AltaGas examined the Statistics Canada MFP indexes for the utilities industry. However, Ms. Frayer and Dr. Schoech acknowledged that the use of these indexes may be problematic for establishing the TFP for electric and gas distribution companies because, for the purposes of the Statistics Canada MFP index, electric distribution is combined with power generation and transmission. Natural gas distribution is combined with water, sewage and other systems.[461]

399. Because of the presence of these items not pertaining to electric distribution, Ms. Frayer's preference was to rely on the Statistics Canada MFP for the utilities sector in general, not the more specific index for electric utilities.[462] Similarly, Dr. Schoech and his colleagues observed that the Statistics Canada MFP for the natural gas and water subsector showed some "significant structural anomalies" and also considered data for the utilities sector in general.[463]

400. The CCA's experts pointed out that the Statistics Canada MFP indexes have several problems that limit their usefulness in this proceeding. First of all, PEG noted that the inclusion of power generation and transmission in the electric sector and the inclusion of water systems in the gas sector substantially reduces the relevance of Statistics Canada's MFP indexes for the electric and gas distribution companies. Second, PEG highlighted the fact that the output of the industry is measured volumetrically and thus may not be an accurate reflection of gas sector productivity growth, as discussed earlier in Section 6.3.6 of this decision. In addition, PEG also expressed a number of other concerns with Statistics Canada's MFP indexes, including the influence of large conservation programs in several Canadian provinces not experienced in

455 Transcript, Volume 17, page 3236, lines 6-8.
456 Transcript, Volume 11, page 2070, lines 1-2.
457 Transcript, Volume 11, pages 2108-2109.
458 Exhibit 472.02, Carpenter rebuttal evidence, page 32.
459 Exhibit 307.01, PEG evidence, page 36.
460 Exhibit 391.02, NERA second report, paragraph 47.
461 Exhibit 110.01, Christensen Associates evidence, paragraph 43; Exhibit 100.02, Frayer evidence, pages 58-66.
462 Exhibit 100.02, Frayer evidence, pages 65-66.
463 Exhibit 110.01, Christensen Associates evidence, paragraphs 44 and 47.

Alberta, the effect of the recent economic recession and the use of value added indexes which ignores the productivity of intermediate inputs.[464]

401. Ms. Frayer[465] and Dr. Carpenter[466] also examined the study of productivity trends at the provincial level prepared by the Center for the Study of Living Standards (CSLS).[467] As Ms. Frayer explained, the CSLS report "provides an analysis of the economic conditions and productivity of ten Canadian provinces over a ten-year period from 1998 to 2007."[468] Ms. Frayer observed that this report used the same methodology and underlying data that Statistics Canada employed in the calculation of its MFP indexes. As a result, Ms. Frayer noted that the CSLS productivity indexes do not differ substantially from the MFP indexes published by Statistics Canada.[469]

402. Because of the similarities between the Statistics Canada and the CSLS analyses, the CCA indicated that its concerns with respect to the Statistics Canada MFP indexes equally apply to the CSLS estimates. Additionally, PEG indicated that in correspondence with the authors of the CSLS study, the authors "conceded that the study used an experimental methodology and is not of a high enough standard to be used in X factor determination."[470]

403. Finally, for this proceeding Ms. Frayer also updated her TFP study performed for the Ontario Energy Board in 2007. Ms. Frayer's updated study covered 78 local distribution companies in Ontario for the period 2002 to 2009 and found negative TFP growth in the range of -0.4 per cent to -1.5 per cent.[471]

404. PEG expressed its concerns with this study primarily relating to methodology and the short sample period. With respect to methodology, PEG took issue with Ms. Frayer's use of line miles as a proxy for the capital quantity trend. The UCA echoed this concern.[472] In addition, PEG noted that Ms. Frayer's sample period was "far too short" to smooth out the effects of annual variations in productivity growth arising from the use of volatile output measures such as energy volumes and peak demand.[473]

Commission findings

405. The Commission agrees with the CCA's experts that because the Statistics Canada MFP indexes include power generation and transmission in the electric sector and water systems in the natural gas sector, these indexes are not suitable for estimating the TFP for distribution companies. The Commission does not share Ms. Frayer's view that looking at a more aggregated MFP index for the utilities sector in general would help to address this problem. As the CCA

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464 Exhibit 307.01, PEG evidence, pages 41-43.
465 Exhibit 100.02, Frayer evidence, page 58.
466 Exhibit 98.02, Carpenter evidence, page 33, A74.
467 The Center for the Study of Living Standards, *New Estimates of Labour, Capital, and Multifactor Productivity Growth and Levels for Canadian Provinces at the three-digit NAICS Level, 1997-2007*, issued on June 8, 2010.
468 Exhibit 100.02, Frayer evidence, page 66.
469 Exhibit 100.02, Frayer evidence, pages 66-68.
470 Exhibit 307.01, PEG evidence, pages 43-44 and Exhibit 376.01, ATCO-CCA-57(b).
471 Exhibit 100.02, Frayer evidence, pages 72-76.
472 Exhibit 299.02, Cronin and Motluk UCA evidence, page 81.
473 Exhibit 645, CCA reply argument, pages 32-33.

explained, such an aggregate index still includes such items as generation, transmission and water systems, which further dilutes the productivity trend of the distribution component.[474]

406. In addition, PEG observed that Statistics Canada uses volumetric output measures for calculating its MFP indexes.[475] As mentioned in Section 6.3.6 above, Dr. Lowry explained that in the presence of a declining use per customer experienced by the gas distribution industry, a gas TFP study based on a volumetric output index will understate the productivity of the gas industry.[476]

407. As Ms. Frayer observed, the CSLS study used the same methodology and underlying data that Statistics Canada employed in calculating its MFP indexes. Accordingly, the Commission considers that this study is prone to the same criticisms as the Statistics Canada indexes. Overall, the Commission considers that while Statistics Canada's MFP indexes and the CSLS report can be a useful reference for gauging the general productivity trends of the utilities sector, these analyses cannot be a substitute for a TFP study for either the electric or gas distribution industries.

408. With respect to Ms. Frayer's updated study on Ontario distribution companies, the Commission shares the CCA's concern that the short period covered by the study (2002 to 2009) does not allow measuring the long-term industry productivity trend. As the Commission observed in Section 6.3.2 of this decision, most experts in this proceeding agreed that a period of less than 10 years will not achieve this purpose.[477] Furthermore, the Commission is not persuaded that a TFP study based exclusively on Ontario distribution companies represents a better indicator of the underlying industry productivity trend for the electric or gas distribution industries compared to NERA's study covering a broad sample of companies from across the United States.

6.3.8 Commission determinations on TFP

409. There are two productivity studies on the record in this proceeding. The first, conducted by NERA, calculated a TFP of 0.96 per cent.[478] This TFP value was based on an analysis of the distribution portion of 72 U.S. electric and combination electric/gas companies over the period of 1972 to 2009.[479] The second study was conducted by PEG on behalf of the CCA for the gas distribution industry and found a TFP in the range of 1.32 to 1.69 per cent. PEG's study examined 34 U.S. gas distribution companies over the period of 1996 to 2009.[480]

410. The ATCO companies, Fortis and AltaGas relied on the various MFP indexes published by Statistics Canada as well as the CSLS study examining productivity in different sectors of the U.S. and Canadian economies for a variety of purposes.[481] As explained in Section 6.3.7 above,

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474 Exhibit 645, CCA reply argument, paragraph 113.
475 Exhibit 307.01, PEG evidence, page 42.
476 Transcript, Volume 14, page 2872, line 20 to page 2873, line 4.
477 Exhibit 307.01, PEG evidence, page 28; Exhibit 631, ATCO Electric argument, paragraphs 61-62; Exhibit 632, ATCO Gas argument, paragraphs 69-70.
478 In its first report NERA estimated a TFP of 0.85 per cent. However, in its second report it accepted one of the adjustments proposed by PEG (related to labour quantity estimation for the period 2002 to 2009). This adjustment resulted in a recalculated TFP estimate of 0.96 per cent.
479 Exhibit 391.02, NERA second report, Table 3.
480 Exhibit 307.01, PEG evidence, page 2.
481 Exhibit 98.02, Carpenter evidence, paragraph 43; Exhibit 100.02, Frayer evidence, page 58; Exhibit 110.01, Christensen Associates evidence, paragraph 43.

the Commission determined that the MFP indexes published by Statistics Canada as well as the CSLS study are unsuitable for determining TFP for either the electric or gas distribution industries.

411. The Commission has evaluated the NERA and PEG TFP studies with respect to a number of issues and criteria discussed by the parties, such as the relevant time period and sample size, the relevance of the U.S. data to Alberta companies, the use of publicly available data and transparent methodology, and the applicability of the obtained TFP number to both gas and electric companies as set out in sections 6.3.2 to 6.3.6 of this decision. Based on this evaluation, the Commission finds that NERA's study is preferable to use in this proceeding given the objectivity and transparency of the data and of the methodology used, the use of data over the longest time period available and the broad based inclusion of electric distribution companies from the United States.

412. In the Commission's view, NERA's study was more objective and transparent compared to PEG's analysis. First, as the Commission observed in Section 6.3.2 above, the choice of a sample period in PEG's study was primarily based on Dr. Lowry's personal judgment, not on objective criteria. Moreover, as set out in Section 6.3.4, PEG's lack of transparency in data processing did not allow either the other parties nor the independent consultant NERA, to fully test and verify its TFP recommendation. As such, while the Commission recognizes the value of a separate productivity study focusing on gas distributors, the drawbacks of PEG's TFP research do not allow the Commission to rely on it.

413. The Commission notes that in addition to the issues discussed in sections 6.3.2 to 6.3.7 above, PEG expressed a number of other concerns with NERA's study relating to the correct index form and the capital quantity index to use, among others.[482] Some of these issues reflect an ongoing academic debate on which consensus has not been reached, or for which there is no right or wrong answer. For instance, PEG advocated the use of a chain-weighted form of a Tornqvist-Theil index, while NERA preferred the use of a multilateral Tornqvist-Theil index.[483] Similarly, PEG indicated that the correct capital quantity measure to use should be the inflation-adjusted value of gross plant, while NERA insisted on using the net plant value.[484] Overall, the Commission considers that PEG's criticisms do not undermine the credibility of NERA's TFP study.

414. The Commission also observes that all of the companies' experts used NERA's study as a starting point for their X factor recommendations despite expressing some reservations about particular aspects of the study and offering various adjustments primarily relating to the sample period.[485]

415. In light of the above considerations, the Commission accepts NERA's methodology and finds that NERA's TFP estimate of 0.96 per cent represents a reasonable starting point for setting an X factor for the Alberta companies. Accordingly, based on NERA's study, the Commission

[482] Exhibit 569.01, PEG rebuttal evidence, redlined pages; Exhibit 478, PEG rebuttal evidence, pages 11-17; Exhibit 609.02, CCA undertaking response: PEG adjustments to NERA.
[483] Transcript, Volume 1, pages 76-77.
[484] Transcript, Volume 1, pages 74-75 and Exhibit 461.02, AUC-NERA-16.
[485] Exhibit 103.05, Cicchetti evidence, page 16; Exhibit 98.02, Carpenter evidence, page 32; Exhibit 100.02, Frayer evidence, page 79; Exhibit 110.01, Christensen Associates evidence, page 15.

finds that a long-term industry TFP of 0.96 per cent represents a reasonable basis for determining the X factors to be used in the PBR plans of the electric distribution companies.

416. With respect to the gas companies, as discussed in Section 6.3.6 above, the Commission agrees with Dr. Lowry's argument that it is necessary to match the output measure to the type of PBR plan (price cap or revenue-per-customer cap).[486] However, in the absence of a reliable and transparent TFP study on the gas distribution industry and information on how changes in the relevant output measures and input measures for electric and gas distribution industries compare to each other over the 1972 to 2009 study period, the Commission is not prepared to make any adjustment to NERA's TFP estimate in order to obtain a TFP estimate for the gas distribution companies.

417. The Commission observes that NERA, ATCO Gas and AltaGas agreed that NERA's study represents a reasonable starting point for determining the TFP trend for gas distributors.[487] The Commission agrees. Accordingly, the Commission finds that NERA's TFP of 0.96 per cent represents a reasonable basis for determining the X factors to be used in the PBR plans of the gas distribution companies.

6.4 Adjustments to arrive at the X factor

418. In this proceeding, parties discussed several potential adjustments to TFP to arrive at the X factor. Specifically, NERA explained that the theory behind PBR plans may require an input price differential and a productivity differential adjustment if an output-based measure is used for the I factor.[488] Additionally, Dr. Carpenter on behalf of the ATCO companies,[489] Dr. Cicchetti on behalf of EPCOR,[490] and Dr. Schoech on behalf of AltaGas[491] expressed their views that NERA's TFP analysis based on the U.S. data needed to be adjusted for the differences in the economy-wide productivity growth between the United States, Canada and Alberta.

419. In addition to the above adjustments, parties discussed whether the companies' proposals to exclude all of or part of capital from the I-X mechanism should have any effect on the X factor. Each of these possible adjustments is addressed in the following sections of this decision.

6.4.1 Input price and productivity differential if an output-based measure is chosen for the I factor

420. Similar to the discussion in Decision 2009-035 dealing with ENMAX's FBR plan,[492] parties to this proceeding pointed out that the choice of an I factor can influence the X factor depending on the productivity that may be embedded in a particular inflation measure.

421. As Dr. Carpenter and Ms Frayer explained, there are two types of inflation measures that can be used for the I factor: input-based and output-based. Input-based measures reflect the change in the prices of goods and services purchased as inputs into the companies' production

486 Exhibit 307.01, PEG evidence, page 12.
487 Exhibit 80.02, NERA report, pages 4 and 5; Exhibit 99.01, Carpenter evidence, page 31; Exhibit 628, AltaGas argument, page 25
488 Exhibit 461.02, AUC-NERA-17(a) and (b).
489 Exhibit 98.02, Carpenter evidence, pages 26-34.
490 Exhibit 233.01, AUC-ALLUTILITIES-EDTI-9(b).
491 Transcript, Volume 8, page 1414, lines 9-25.
492 Decision 2009-035, paragraphs 126-128.

process. A labour cost index such as AWE or AHE represents an example of an input price index since they track the changes in the wages and salaries of company's employees and contracted labour services. In contrast, output-based measures reflect the change in the prices of the basket of goods and services that are outputs of the economy and are typically purchased by final consumers rather than by companies as inputs. The CPI (consumer price index) would usually be an example of this type of measure.[493]

422. Given that the purpose of the I factor in a PBR plan is to track the prices of the inputs used by the electric or gas distribution industries (and therefore, the companies), the use of an input-based price index is preferred. However, on many occasions, the desired input price index may not be readily available or may not exist at all.[494] As a result, PBR plans may need to use output-based measures that are readily available, widely known and easy to explain to consumers, stakeholders and regulators.[495] NERA pointed out that the CPI is the most common inflation measure in PBR plans in Canada, while the GDP price index (also an output-based measure) is dominant in the United States.[496]

423. Nevertheless, using an output-based inflation index in a PBR plan may be problematic. Because the measure of output inflation already incorporates the effects of economy-wide productivity gains, such an index would not necessarily be indicative of the input price inflation likely to be experienced by the industry and, accordingly, the companies during the plan term. As a result, it may be necessary to adjust the TFP estimate when determining the X factor to correct for the difference between the output inflation included in the inflation factor and the industry input inflation.[497]

424. NERA and Dr. Carpenter explained that for practical purposes this adjustment consists of two adjustments to TFP to arrive at the X factor: a productivity differential and an input price differential.[498] In its evidence, PEG explained the logic behind those two adjustments as follows:

> The productivity differential is the difference between the MFP trends of the industry and the economy. The X will be larger, slowing the [I-X index] growth, to the extent that the MFP growth of the economy is slow. The input price differential is the difference between the input price trends of the economy and the industry. X will be larger (smaller) to the extent that the input price trend of the economy is more (less) rapid than that of the industry.[499]

425. As Fortis' expert pointed out, in this case an X factor based on TFP with these two adjustments may be interpreted as the difference between the productivity growth rate of the industry and the productivity growth rate included in the output inflation measure used. On the other hand, if an input price index is used for the I factor, no adjustment to TFP is required. In this case, the resulting X factor would reflect the productivity growth of the industry.[500]

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493 Exhibit 476.01, Carpenter rebuttal evidence, page 67; Exhibit 100.02, Frayer evidence, page 33.
494 Exhibit 476.01, Carpenter rebuttal evidence, page 67.
495 Exhibit 100.02, Frayer evidence, pages 33-34.
496 Exhibit 391.02, NERA second report, paragraph 65.
497 Exhibit 476.01, Carpenter rebuttal evidence, page 67; Exhibit 100.02, Frayer evidence, page 54; Exhibit 628, AltaGas argument, pages 12-13.
498 Exhibit 461.02, AUC-NERA-17(b) and Exhibit 476.01, Carpenter rebuttal evidence, page 67.
499 Exhibit 307.01, PEG evidence, pages 20-21.
500 Exhibit 100.02, Frayer evidence, page 52.

Commission findings

426. The interaction between the I factor and the X factor described above is based on a well-established theoretical foundation, as demonstrated by the agreement of parties on the need to adjust TFP in determining an X factor if an output-based inflation measure is chosen for the purpose of the PBR plan.[501] Consequently, the parties advised that, when possible, it is preferable to use input-based price indexes for the I factor of the PBR plan, since using such indexes avoids the need for an input price differential and a productivity differential adjustment to TFP.

427. As set out in Section 5 of this decision, the Commission approved a composite I factor consisting of AWE and CPI indexes for Alberta. While the AWE index represents an example of an input-based measure, the CPI is generally regarded as an output rather an in input price index. However, as the Commission explained in Section 5.2.3 above, in the context of this proceeding, the Alberta CPI will be used only to monitor price trends for the companies' non-labour inputs. EPCOR, AltaGas and ATCO Gas submitted that because the Alberta CPI is a good proxy for the price changes for that particular group of expenditures, it may be considered an input price index for the purpose of their composite I factors.[502] The Commission agrees.

428. Accordingly, since both components of the approved I factors can be considered input-based price indexes, there is no need in this case for the Commission to consider an adjustment to TFP for an input price differential or productivity differential in the calculation of the X factor.

6.4.2 Productivity gap adjustment

429. As discussed in Section 6.3.1 above, NERA's study used a population of 72 U.S. electric and combination electric/gas companies. In these circumstances, Dr. Carpenter indicated that to the extent that utilities in Canada have different productivity expectations than utilities in the U.S., an adjustment to the NERA's TFP number would be required in a Canadian PBR context.[503]

430. Dr. Carpenter observed that there is a well-documented productivity gap between the Canadian and the U.S. economies, with Canadian productivity growth rates consistently lower than productivity growth in the U.S. For example, Dr. Carpenter pointed to a Statistics Canada study that found that average annual MFP growth was 0.9 percentage points lower in Canada than in the United States from 1961 to 2008.[504] In addition, Dr. Carpenter observed that in its TFP analysis, NERA showed that on average, productivity in the U.S. economy grew 0.95 percentage points per year faster that productivity in the Canadian economy over the 1972 to 2009 period.[505]

431. At the same time, the ATCO companies' expert acknowledged that while the existence of the economy-wide productivity gap has been documented by government statistics and academic studies, the specific causes of the gap are not well understood and it is not clear whether a similar

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501 Transcript, Volume 1, pages 141-142; Transcript, Volume 4, pages 611-612; Transcript, Volume 8, page 1415; Transcript, Volume 11, pages 2133-2134; Transcript, Volume 13, page 2589.

502 Exhibit 630.02, EPCOR argument, paragraph 31; Exhibit 628, AltaGas argument, pages 12-13; Exhibit 648.02, ATCO Gas reply argument, paragraph 94.

503 Exhibit 98.02, Carpenter evidence, pages 25-26.

504 Baldwin, John and Wulong Gu, *Productivity Performance in Canada, 1961 to 2008: An Update on Long-term Trends*, Statistics Canada, August 2009.

505 Exhibit 98.02, Carpenter evidence, page 29.

productivity gap exists in the electric and gas utility sector. For example, Dr. Carpenter noted that studies relying on the Statistics Canada data typically define the utility sector more broadly, including power generation and transmission in the electric sector and water and sewage utilities in the gas sector.[506] Thus, these studies may not provide an accurate estimate of productivity growth for electric or gas distribution companies. As a result, Dr. Carpenter conceded that there is no evidence to permit a direct comparison of Canadian and U.S. productivity growth rates for electric or gas distribution companies.[507]

432. Despite the lack of direct empirical evidence, Dr. Carpenter concluded that it is likely that the economy-wide productivity gap between Canada and the U.S. persists at the utility sector level. Dr. Carpenter arrived at this conclusion as a result of following considerations.[508]

- First, Dr. Carpenter indicated that he was not aware of any evidence that differences in the composition of the two economies drive the different rates of productivity growth. For example, Dr. Carpenter noted that the proportion of total GDP generated by the various sectors of the Canadian and the U.S. economies is not very different.
- Second, Dr. Carpenter noted that he was not aware of any compelling evidence that there is one sector or a group of sectors in the Canadian and the US economies that drives the productivity gap. According to Dr. Carpenter, there is evidence that the productivity gap occurs in a wide range of sectors, which is likely to include the utility sector.
- Third, Dr. Carpenter observed that while there is some disagreement among researchers as to the possible explanations for the U.S.-Canada gap, he had seen no reason to believe that the productivity gap is unlikely to affect the utility sector.

433. As a result of these considerations, Dr. Carpenter indicated that NERA's TFP estimate for the U.S. companies needed to be adjusted for the observed U.S.-Canada productivity gap. Using the economy-wide productivity estimates from Statistics Canada and the U.S. Bureau of Labour Statistics presented in NERA's report, Dr. Carpenter proposed an adjustment of approximately -1.5 percentage points to NERA's TFP.[509]

434. Furthermore, Dr. Carpenter expressed his view that the recommended productivity gap adjustment was conservative for Alberta. The ATCO companies' expert noted that the CSLS report[510] and another productivity study[511] show a Canada-Alberta productivity gap, with Alberta having slower productivity growth in the utility sector and in the business sector in general. However, because ATCO Electric and ATCO Gas make up a significant part of the utility sector in Alberta, Dr. Carpenter indicated that adjustment for a Canada-Alberta productivity gap may not be appropriate since the resulting X factor would be "ATCO-specific" rather than reflective of the industry productivity trends.[512]

435. AltaGas agreed with Dr. Carpenter that in the case that the TFP analysis "did not focus on the Canadian gas distribution industry, an adjustment for the U.S.-Canada productivity gap

506 Transcript, Volume 6, page 1004, lines 4-25.
507 Exhibit 98.02, Carpenter evidence, pages 26-27.
508 Exhibit 98.02, Carpenter evidence, pages 27-29.
509 Exhibit 98.02, Carpenter evidence, page 30, Tables 2 and 3.
510 The CSLS report was discussed in Section 6.3.7 of this decision.
511 Rao, Someshwar, Andrew Sharpe and Jeremy Smith, *An Analysis of the Labour Productivity Growth Slowdown in Canada since 2000*, International Productivity Monitor, Spring 2005.
512 Exhibit 98.02, Carpenter evidence, pages 33-34.

would generally be appropriate.[513] With respect to the Canada-Alberta productivity gap, AltaGas observed that the CSLS report (from which the existence of such a gap was inferred) was conducted on an experimental basis. As such, AltaGas did not propose to make an adjustment for differences in productivity growth between Alberta and Canada.[514]

436. EPCOR submitted that neither the company itself nor its expert Dr. Cicchetti have proposed an adjustment for the productivity differences between the U.S. and Canada or between Canada and Alberta. During the hearing, Dr. Cicchetti explained that the data for Canadian companies do not exist in a fashion that would allow anyone to have an authoritative opinion on the difference in productivity between Canadian and U.S. electric distribution utilities.[515] At the same time, when establishing the components of EPCOR's PBR plan, Dr. Cicchetti urged the Commission to recognize that the actual trend in input prices for labour in Alberta are likely to be above the past trends in the U.S. reflected in NERA's data.[516] As a result, EPCOR submitted that the Commission should not increase the X factor "to something more than -1.0 per cent" that Dr. Cicchetti recommended for the company, given the difference in U.S. and Alberta labour economics.[517]

437. Fortis noted that the company did not ground its X factor approach or recommendation on the basis of a productivity gap. Furthermore, Fortis submitted that the relevant Canada to Alberta considerations in the company's proposal were with respect to the I factor, where the appropriate "Albertasizing" of input price measures was undertaken.[518]

438. The CCA did not believe that any adjustment to the X factor to account for the U.S.-Canada productivity gap was necessary. Having examined the analysis of MFP conducted in several papers by Statistics Canada, PEG found that productivity growth differences between the United States and Canada "vary so widely by industry as to render economy-wide differences in productivity growth useless in quantifying differences in productivity growth between specific industries in the two countries."[519] In addition, PEG observed that the productivity gap between the U.S. and Canada was largely due to differences in sectors that do not include utilities, such as mining and oil extraction and manufacturing.[520]

439. In a similar vein, NERA indicated that it was not aware of any evidence to point to a productivity gap between U.S. and Canadian utilities:

> NERA has seen no evidence to point to a productivity gap between US and Canadian utilities. The existence of a macroeconomic productivity gap between the US and Canada does not necessitate the existence of a productivity gap between US and Canadian utilities – or even suggest such a gap for companies, which operate as regulated utilities in markets subject to highly similar sets of accounting, administrative and legal institutional arrangements in the US and Canada.[521]

513 Exhibit 628, AltaGas argument, page 30.
514 Exhibit 628, AltaGas argument, page 31.
515 Transcript, Volume 11, page 2009, lines 16-24.
516 Exhibit 233.01, AUC-ALLUTILITIES-EDTI-9(b).
517 Exhibit 630.02, EPCOR argument, paragraphs 74-75.
518 Exhibit 633, Fortis argument, paragraphs 130-131.
519 Exhibit 376.01, ATCO-CCA-42(c).
520 Exhibit 376.01, ATCO-CCA-42(c).
521 Exhibit 291.02, Calgary-NERA I-9(c), Exhibit 195.01, AUC-NERA-7.

440. Calgary stated that there is fundamentally little if any difference between the productivity of the U.S. and Canadian distribution utilities.[522] Similarly, the UCA expressed its concerns with establishing the existence of a productivity gap between U.S. and Canadian distribution companies based on the difference in productivity in the overall Canadian economy compared to the overall U.S. economy. In their evidence, Dr. Cronin and Mr. Motluk presented the results of various studies of Canadian electric and gas distribution utilities showing that the TFP growth rates of Canadian distribution companies were "notably higher" than for the U.S. distribution companies as measured by NERA's TFP growth rate.[523] As such, the UCA's experts argued that there was a reverse productivity gap between U.S. and Canadian distribution companies.[524]

Commission findings

441. Parties did not dispute the fact that there presently exists a well-recognized difference between the rate at which the U.S. and the Canadian economies have been able to improve productivity (referred to as a "productivity gap"). Using macroeconomic productivity data from Statistics Canada and the U.S. Bureau of Labour Statistics, NERA showed that, on average, productivity in the U.S. economy grew 0.95 percentage points per year faster that productivity in the Canadian economy over the 1972 to 2009 period.[525]

442. At the same time, parties could not agree on whether the same productivity gap exists between the U.S. and Canadian electric and gas distribution industries. Little direct evidence on whether a gap exists is available. Dr. Carpenter and Dr. Cicchetti pointed to the fact that it is not possible to directly review the productivity gap in the electric and gas utility sectors, as no data on productivity growth for Canadian electric and gas companies exist.[526] The UCA experts proposed examining TFP growth estimates of Canadian utilities obtained from various regulatory proceedings for this purpose. However, in the Commission's view, because the TFP estimates introduced by Dr. Cronin and Mr. Motluk represent a variety of sources, methods, samples and time periods, it is uncertain whether these estimates can be directly compared to NERA's TFP calculation to make a judgment on the existence of a productivity gap for the electric and gas distribution industries between the two countries.[527] As such, the Commission will proceed with evaluating the indirect evidence of a productivity gap between U.S. and Canadian utilities.

443. On a conceptual level, the Commission agrees with NERA's and the interveners' proposition that the existence of a macroeconomic productivity gap between the U.S. and Canada does not mean that there is a productivity gap between U.S. and Canadian utilities. As Dr. Lowry explained:

> And also the thrust of my evidence is that if you look under the hood of the Canadian economy and go sector by sector, it's nothing, you know, remotely true that all the sectors are behind their American counterparts. The numbers are just all over the place. So there's very bad predictive value by saying that for a given industry just because the Canadian economy's productivity trend is slower that therefore a given sector should be slower.[528]

[522] Exhibit 629, Calgary argument, page 28.
[523] Exhibit 299.02, Cronin and Motluk UCA evidence, pages 76-79 and 86-87.
[524] Exhibit 634.02, UCA argument, paragraphs 134-135.
[525] Exhibit 80.02, NERA report, page 20, Table 4.
[526] Exhibit 476.01, Carpenter rebuttal evidence, page 41; Transcript, Volume 11, page 2009, lines 16-24 (Cicchetti).
[527] Exhibit 299.02, Cronin and Motluk UCA evidence, pages 78-79.
[528] Transcript, Volume 13, page 2562, lines 11-19.

444. To examine which particular sectors of the Canadian economy contribute to a productivity gap, parties relied on a number of government and academic studies. For example, Dr. Carpenter observed that one Statistics Canada study[529] found evidence of the labour productivity gap in six of the nine industries examined, including utilities and transportation, manufacturing, retail trade, information and cultural industries; and finance, insurance, and real estate. Another study[530] that Dr. Carpenter relied on identified a U.S.-Canada productivity gap in 20 of 33 categories, including electric utilities, gas utilities, mining, food, textiles, printing, and electrical machinery.[531]

445. However, the Statistics Canada study[532] referenced by the CCA's experts, PEG, did not support this conclusion and showed that "the MFP trend of the engineering sector of the economy which includes energy utilities actually exceeded that of the U.S. over a recent sample period."[533] Another study by Statistics Canada[534] quoted by PEG showed that in the 2000 to 2008 period, the decline in the business sector MFP growth rate was due chiefly to declining productivity in two industrial classifications: mining and oil and gas extraction, and manufacturing.[535] The UCA also presented the results of an academic study[536] showing that for the period from 1961 to1995, Canada was "significantly more productive than the United States in coal mining, construction, tobacco, petroleum refining, electric utilities, and gas utilities."[537]

446. Without engaging in a debate on the methodology, time period and relevance of the academic studies discussed in this proceeding,[538] the Commission observes that there is no consensus in the literature on whether a productivity gap exists for the utility sector in general or for the electric and gas distribution sectors in particular. On a related issue, Dr. Carpenter pointed out that there remains a disagreement among the researchers as to the possible explanations for the U.S.-Canada productivity gap.[539]

447. Furthermore, as Dr. Carpenter indicated, some of the academic studies on productivity referenced by the parties in this proceeding refer to the Canadian utility sector in general, which includes power generation and transmission in the electric utilities sector and water and sewage systems in the natural gas utilities sector.[540] As such, it is uncertain whether the productivity of the utilities sector reported in the studies is an accurate reflection of the electric and gas distribution companies' TFP growth.

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529 Baldwin, John and Wulong Gu, *Productivity Performance in Canada, 1961 to 2008: An Update on Long-term Trends*, Statistics Canada, August 2009 (No. 25), Statistics Canada.

530 Gu, Wulong and Mun Ho, *A Comparison of Industrial Productivity Growth in Canada and the United States*, Published in Industry-level Productivity and International Competitiveness between Canada and the United States, 2001.

531 Exhibit 98.02, Carpenter evidence, page 28.

532 Baldwin, Gu and Yan, *Relative Multifactor Productivity Levels in Canada and the United States: A Sectoral Analysis*, The Canadian Productivity Review, June 2008 (No. 19), Statistics Canada.

533 Exhibit 636, CCA argument, paragraph 102.

534 Baldwin and Gu, *Productivity Performance in Canada, 1961 to 2008: An Update on Long-term Trends,* The Canadian Productivity Review, August 2009 (No. 25), Statistics Canada.

535 Exhibit 636, CCA argument, paragraph 102.

536 Lee, Frank C., and Jianmin Tang. 2000. *Productivity Levels and International Competitiveness between Canadian and U.S. Industries.* American Economic Review, 90(2): 176-179.

537 Exhibit 634.02, UCA argument, paragraphs 136-138.

538 Exhibit 476.01, Carpenter rebuttal evidence, pages 42-46; Exhibit 650, AltaGas reply argument, paragraph 87.

539 Exhibit 98.02, Carpenter evidence, page 29.

540 Exhibit 98.02, Carpenter evidence, page 26; Exhibit 476.01, Carpenter rebuttal evidence, page 45.

448. In light of the conflicting evidence from the government and academic research, and the uncertainty of whether the results of such research can be used for establishing the existence of a productivity gap between U.S. and Canadian distribution utilities, the Commission considers that no definitive conclusion can be reached on the existence of such a gap. Further, the Commission finds it to be significant that parties observed the business, operational and regulatory similarities between utilities in both jurisdictions. For example, NERA commented on the similarity of the institutional frameworks in which the Canadian and U.S. utilities operate. As NERA explained:

> [F]rom the constitutional foundation through to administrative practices, accounting practices and judicial review, Canada and the United States have virtually indistinguishable regulatory environments – so much so that the US *Hope* and *Bluefield* decisions are even cited in Canadian rate cases.[541]

449. Dr. Cicchetti also pointed to similarities in the business environment between the utilities in the two countries by observing that electric and gas distribution companies in both the United States and Canada "are certainly the last remaining holdout in the U.S. context of unionized employees."[542]

450. In light of these considerations, the Commission finds that no adjustment to NERA's TFP is necessary to account for the observed economy-wide productivity gap between the U.S. and Canada. The Commission observes that Dr. Carpenter was not aware of any jurisdiction in Canada that has adjusted a TFP estimate in setting the X factor in recognition of the productivity gap between the two countries.[543]

451. With respect to a Canada-Alberta productivity gap, the Commission notes that Dr. Carpenter's conclusions as to the existence of such a gap were largely derived from the examination of the CSLS study.[544] However, as the Commission explained earlier in this section and in Section 6.3.7, because the CSLS study used the same methodology and underlying data that Statistics Canada employed in calculating its MFP indexes, it is not clear to what degree the results of this study are reflective of the productivity trends in the electric and gas distribution industries.

452. More importantly, the Commission explained in Section 6.2 of this decision that the X factor should reflect the average rate of productivity growth in the industry. Accordingly, the Commission agrees with Dr. Carpenter's observation about the size of the ATCO companies and concludes that because the companies in this proceeding make up a large part of the utility sector in Alberta, an adjustment for a Canada-Alberta productivity gap (in the utility sector) would result in an X factor that would reflect the companies' own experience rather than industry productivity trends.[545]

453. Dr. Cicchetti proposed that when setting the X factor for Alberta companies, some recognition be given to the fact that the actual trend of input prices for labour in Alberta is likely to be above the past trends in the U.S. that are reflected in NERA's TFP estimates.[546] In

541 Exhibit 391.02, NERA second report, page 20.
542 Transcript, Volume 11, page 2071, lines 3-6.
543 Transcript, Volume 4, page 635, lines 7-11.
544 Exhibit 98.02, Carpenter evidence, page 33.
545 Exhibit 98.02, Carpenter evidence, pages 33-34.
546 Exhibit 233.01, AUC-ALLUTILITIES-EDTI-9(b).

EPCOR's view, the consequence of this would be that NERA's TFP growth rate would be higher than the actual TFP growth rate for Alberta.[547]

454. The Commission has a number of concerns with the EPCOR proposition. First of all, Dr. Cicchetti did not provide any information on the relative labour inflation in Alberta and the United States for NERA's study period to support his conclusion that labour inflation in Alberta has been consistently higher than labour inflation in the U.S. over this entire period.

455. Furthermore, the actual impact of labour inflation on the TFP estimate is not so direct as to warrant an immediate upward adjustment to NERA's estimates. NERA explained that its overall input index (in the form of a Tornqvist-Theil volume index) primarily captures changes in input volume.[548] Because NERA used the number of employees as a labour quantity measure,[549] the resulting TFP estimate is largely, but not completely, insulated from the effect of labour inflation. NERA explained that its overall input index "is affected by input prices to the extent that the input expenses are the shares by which the input volumes are weighted."[550] Since NERA used nominal dollars to construct the input price shares,[551] adjusting for higher labour inflation (assuming that the labour inflation in Alberta was consistently higher than in the United States) would result in a higher share of labour in NERA's input index. However, a higher share of labour in the overall input index does not necessarily lead to a reduction to TFP. For example, if the rate of growth in the labour index (i.e., labour quantity) were lower than the rate of growth of the capital and materials indexes (quantities of capital and materials), assigning more weight to the labour index would actually result in a lower overall input index. Holding the output index constant, this would result in a higher TFP growth.

456. In the absence of any analysis on how historical Alberta labour inflation would affect NERA's TFP estimate, the Commission cannot accept EPCOR's proposition that an adjustment to the TFP factor is necessary to account for the difference in U.S. and Alberta labour economics.

6.4.3 Effect on the X factor of excluding capital from the application of the I-X mechanism

457. Because EPCOR's proposed PBR plan indexes only operating costs and excludes capital costs, Dr. Cicchetti noted that a PFP (partial productivity factor) measuring only changes in O&M productivity was a relevant measure to use instead of TFP as a basis for EPCOR's X factor.[552] The ATCO companies agreed with this logic and submitted that if all capital expenditures were to be excluded from indexing under the PBR plan, a different X factor would likely be required based on the PFP associated with O&M.[553]

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[547] Exhibit 630.02, EPCOR argument, paragraphs 74-75.

[548] Exhibit 195.01, AUC-NERA-3(a) and (d).

[549] As NERA explained in its second report, before 2002, NERA used number of employees for labour quantity. Because FERC Form 1 no longer contains employee data after 2002, NERA estimated the number of employees using the inflation-adjusted distribution payroll growth for the years 2002 to 2009. (Exhibit 391.02, NERA second report, page 10). In either period, labour quantity is measured by a number of employees, and is not reflective of labour inflation.

[550] Exhibit 195.01, AUC-NERA-3(d).

[551] Exhibit 195.01, AUC-NERA-3(b).

[552] Exhibit 103.05, Cicchetti evidence, page 20.

[553] Exhibit 631, ATCO Electric argument, paragraph 102 and Exhibit 632, ATCO Gas argument, paragraph 112.

458. The UCA argued that the same reasoning applies to the exclusion from indexing of a portion of capital expenditures. Because NERA's TFP estimate was based on the entirety of the distribution companies' inputs (i.e., capital, labour and materials), the UCA argued that the exclusion of some or all capital from the I-X mechanism would require an adjustment to NERA's TFP and the resulting X factor.[554] At the same time, the UCA observed that the issue of what the relevant X factor should be in this case was not addressed in this proceeding, and a separate process was required:

> However, if the Commission determines that there is need for a capital adjustment outside of the I-X mechanism, then a separate proceeding is definitely required. The proceeding would have to examine the appropriate X factor having regard to the exclusion of a material portion of capital from the I-X mechanism. This alternative creates additional regulatory burden. It would create uncertainty for the Applicants and the ratepayers. The UCA does not recommend this alternative.[555]

459. PEG observed that to the extent that the capital expenditures excluded from indexing are sizable and involve the "normal kinds of [capital expenditures] undertaken by the sampled utilities," it may be necessary to raise the TFP estimate.[556] To support its view, PEG showed that for its sample of companies, excluding 10 per cent of capital expenditures causes TFP growth to increase from 1.32 per cent to 1.53 per cent.[557]

460. In response, the ATCO companies submitted that based on the structure of their PBR plans, there is no need to adjust the TFP (and the resulting X factor). Specifically, the ATCO companies noted that while some capital expenditures were included as flow-through factors under the companies' respective plans, the vast majority (approximately 85 per cent for ATCO Electric and 95 per cent for ATCO Gas) of their revenues were covered under the I-X portion of the plan. As such, the ATCO companies argued that their PBR plans were comprehensive, and thus no adjustment to the X factor was required.[558]

461. Similarly, AltaGas indicated that under the revenue-per-customer cap proposed by the company, the impact of capital expenditures removed from the I-X mechanism and included in the proposed flow-through factor represented only around five per cent of the company's total revenue requirement. AltaGas argued that given the relative size, scope and the effective isolation of the projects included in the flow-through factor from other elements of the company's plan, there was no reason to adjust the X factor for the exclusion of some part of capital.[559]

Commission findings

462. The Commission agrees in principle with the CCA's and the UCA's view that because NERA's study measures changes in output compared to changes in all of the companies' inputs (that is, labour, materials and capital), NERA's TFP estimate may not be precisely applicable to PBR plans that exclude all or a part of capital from the application of the I-X mechanism. However, for the reasons explained below, the Commission has not made any adjustment to

[554] Exhibit 634.02, UCA argument, paragraph 204.
[555] Exhibit 634.02, UCA argument, paragraph 205.
[556] Exhibit 307.01, PEG evidence, page 60.
[557] Exhibit 307.01, PEG evidence, page 29.
[558] Exhibit 631, ATCO Electric argument, paragraph 103 and Exhibit 632, ATCO Gas argument, paragraph 113.
[559] Exhibit 628, AltaGas argument, pages 31-32.

NERA's TFP estimate to account for capital that is excluded from the application of the I-X mechanism.

463. With respect to excluding all capital from the application of the I-X mechanism, the Commission explained in Section 2.3 that it did not accept EPCOR's proposal to exclude capital and apply the I-X mechanism only to the O&M and other non-capital costs. As such, no consideration of the partial productivity factors of the type proposed by Dr. Cicchetti is required in determining the X factor for EPCOR's proposed PBR plan.

464. With respect to the exclusion of some capital, as further discussed in Section 7.3.2.4 of this decision, the Commission's preferred method of dealing with companies' concerns regarding unusual capital expenditures is through the use of capital trackers. The Commission acknowledges that, in theory, because the capital expenses subject to these trackers will be not be subject to the I-X mechanism, NERA's TFP number may need to be adjusted.

465. However, the Commission observes that the direction of any TFP adjustment to account for the exclusion of some of the capital is not clear, as demonstrated by the parties' conflicting evidence on this subject. Dr. Cicchetti's analysis showed that excluding capital from NERA's TFP estimate results in a more negative PFP trend, and therefore the X factor when capital is excluded from the application of the I-X mechanism should be lower than if capital were included.[560] In contrast, PEG showed that for its sample of companies, excluding 10 per cent of capital expenditures causes TFP to rise. Accordingly, to the extent that the capital expenditures excluded from indexing are sizable, the CCA experts advocated a higher X factor.[561]

466. Additionally, the Commission indicated in Section 7.3.4 below that it is not approving any of the capital factors proposed by the companies as part of this decision. In Section 7.3.4, the Commission has invited the companies to file their capital proposals in their first capital tracker filing on or before November 2, 2012. In its submissions, the UCA was referring to the exclusion of a "material portion of capital" from the application of the I-X mechanism.[562] AltaGas and the ATCO companies argued that their proposed capital flow-through factors (which, in AltaGas' view were of a nature similar to NERA's definition of a capital tracker) would not have a large effect on the overall revenue requirement.[563]

467. In light of this conflicting evidence and the resulting uncertainty as to the materiality and the direction of any adjustment to account for the exclusion of some capital from the I-X mechanism, the Commission will not be making any adjustments to TFP during the PBR term to account for the fact that some capital may be excluded from the application of the I-X mechanism.

560 Exhibit 103.05, Cicchetti evidence, pages 22-24.
561 Exhibit 307.01, PEG evidence, pages 29 and 60.
562 Exhibit 634.02, UCA argument, paragraph 205.
563 Exhibit 628, AltaGas argument, page 32; Exhibit 631, ATCO Electric argument, paragraph 103; Exhibit 632, ATCO Gas argument, paragraph 113.

6.5 Stretch factor

6.5.1 Purpose of the stretch factor

468. Generally speaking, a stretch factor is an additional percentage applied to the X factor, thereby increasing the overall value for X and thus slowing the price or revenue cap growth determined by the I-X indexing mechanism.[564]

469. Parties to this proceeding differed in their interpretation as to the purpose of the stretch factor and based their recommendations accordingly. Nevertheless, most parties to this proceeding agreed that the rationale behind the stretch factor is to share with customers the benefits of the expected acceleration in productivity growth as the company transitions from a cost of service ratemaking system to performance-based regulation. Dr. Cicchetti explained the logic behind this reasoning as follows:

> In North America, an industry productivity trend that is estimated using historical data will overwhelmingly reflect the productivity experience of an industry that has been regulated using cost of service methods. [...] A principal rationale for PBR is to create stronger performance incentives compared with cost of service regulation. This, in turn, implies that when utilities become subject to PBR, it is expected that they will achieve incremental productivity gains compared to what has been observed under traditional cost of service regulation. The productivity "stretch factor" reflects the expectation that productivity growth will increase, at least temporarily, under incentive regulation and adding this "stretch" goal to an estimate of the historical productivity trend embodies an estimate of these expected, incremental productivity gains in the approved X-factor.[565]

470. Another EPCOR expert, Dr. Weisman, further elaborated on this reasoning and emphasized that the stretch factor is designed to ensure that consumers share in part of the efficiencies created by moving from the cost of service to the PBR regime:

> DR. WEISMAN: The typical rationale, and one that I would agree with, is that when you move to a more high powered regulatory regime, such as price cap regulation, that this will fundamentally change the incentives of the firm, that it will be able to enhance its efficiencies, and the stretch factor is designed to ensure that consumers share in part of those efficiencies. So it basically bounces up our historical view of productivity growth to account for the change of the enhanced incentives that accompany price cap regulation relative to traditional cost-of-service regulation.
> Q. So it's good for that period of time when you move from cost of service into incentive-based regulation? Is that fair?
> A. DR. WEISMAN: Generally the focus is on the transition. You probably heard the so-called low-hanging fruit argument, that the -- in the initial transition the efficiency gains what we can change, how we can innovate are more obvious and apparent than they are later on.[566]

471. AltaGas,[567] NERA,[568] the UCA[569] and Calgary,[570] supported this rationale behind the stretch factor. Accordingly, these parties supported the inclusion of a stretch factor in the

564 Exhibit 98.02, Carpenter evidence, page 34; Exhibit 307.01, PEG evidence, page 16.
565 Exhibit 103.05, Cicchetti evidence, pages 27-28.
566 Transcript, Volume 9, page 1766, lines 4-22.
567 Exhibit 110.01, AltaGas application, paragraph 45 and Transcript, Volume 9, page 1689, lines 19-24.
568 Exhibit 195.01, AUC-NERA-12(a) and Transcript, Volume 1, page 116, lines 21-24.
569 Transcript, Volume 17, page 3287, lines 14-25.

companies' PBR plans. The parties' specific recommendations as to the size of the stretch factor are discussed in the following section of this decision.

472. In Ms. Frayer's view, which Fortis adopted, a stretch factor is a mechanism to adjust the company's revenue or rates each year to reflect firm-specific expected productivity gains vis-à-vis the gains expected for the industry as a whole. In other words, according to Ms. Frayer, a stretch factor "creates an incremental incentive for productivity, in order to "catch-up" with the rest of industry, in the case of a company that is underperforming."[571] In that regard, Fortis argued that because of its strong productivity performance in recent years (as demonstrated by the continued reduction in controllable operating costs per customer since 2004), there was no "low-hanging fruit" for the company to pick under PBR.[572]

473. The CCA and its expert, Dr. Lowry, indicated that both the operating efficiency of the company and the difference between the incentive power of the current regulation and the PBR plan should form part of the consideration as to whether to add a stretch factor.[573] Similarly, Dr. Carpenter expressed his view that both of these considerations are relevant in determining whether a stretch factor is required:

> If there is evidence to suggest that a particular utility is less efficient than the industry as a whole, and if the incentives for improving efficiency are likely to be much stronger in the future than they have been in the past, then it might be reasonable to expect that utility to be able to achieve more rapid productivity growth than the historical trend rate measured in a TFP study. A stretch factor may then be appropriate.[574]

474. However, the Dr. Lowry and Dr. Carpenter did not agree on whether a stretch factor should be assigned to Alberta companies. In Dr. Carpenter's view, it is not clear whether the PBR regime will create much stronger incentives for efficiency than the existing cost of service regime since the current regulation in Alberta contains "significant efficiency incentives because of the time between rate cases and the forward-looking test periods."[575] As such, the ATCO companies argued that a stretch factor should not be applied to their PBR plans.[576]

475. In contrast, Dr. Lowry and his colleagues at PEG argued that the current regulatory system in Alberta, under which the companies file rate cases every two years, has "weak performance incentives."[577] Accordingly, Dr. Lowry noted it is reasonable to expect that there will be some productivity acceleration in Alberta with the adoption of a PBR regime and, as a result, a stretch factor should be included in the companies' PBR plans.[578]

476. Finally, in discussing whether a stretch factor should be a part of the companies' PBR plans, parties to this proceeding pointed to an inter-relationship between a stretch factor and an ESM (earnings sharing mechanism). Specifically, all the companies contended that a stretch factor and an ESM were mutually exclusive and preferred to keep only the one alternative of

570 Exhibit 298.02, Calgary evidence, paragraph 133 and Transcript, Volume 15, page 2935, lines 18-25.
571 Exhibit 100.02, Frayer evidence, page 79.
572 Exhibit 633, Fortis argument, paragraphs 144-146.
573 Exhibit 636, CCA argument, paragraph 108 and Transcript, Volume 13, pages 2564-2565.
574 Exhibit 476.01, Carpenter rebuttal evidence, page 62.
575 Exhibit 476.01, Carpenter rebuttal evidence, page 58.
576 Exhibit 631, ATCO Electric argument, paragraph 108; Exhibit 632, ATCO Gas argument, paragraph 118.
577 Transcript, Volume 13, page 2564, lines 6-10 and Exhibit 307.01, PEG evidence, page 46.
578 Transcript, Volume 13, page 2564, lines 3-10 and Exhibit 636, CCA argument, paragraph 118.

their choice.[579] Accordingly, EPCOR and AltaGas argued that an ESM should not be a part of their plans, given that their PBR proposals contained a stretch factor.[580] Conversely, in the view of the ATCO companies and Fortis, the inclusion of an ESM in their PBR plans provided an additional justification for not imposing a stretch factor.[581]

477. On this issue, NERA commented that, although there may be some aspects of a trade off between an ESM and a stretch factor, it does not view an ESM and a stretch factor as mutually exclusive.[582] The CCA and the UCA experts shared this view as demonstrated by the fact that PEG's incentive power model and the X factor menu advocated by Dr. Cronin and Mr. Motluk included both an ESM and a stretch factor.[583]

478. Calgary also offered that there is no mutual exclusivity between an ESM and a stretch factor. In Calgary's view, a stretch factor is intended to deal with the attempt to capture the additional efficiencies resulting from the transition from the cost of service regime to PBR. In contrast, the ESM is intended to address the proper sharing of any efficiencies derived from operating under the I-X mechanism that are achieved during the PBR term.[584] Calgary noted that a number of PBR plans in North America have both of these elements, as shown in NERA's second report.[585]

Commission findings

479. The Commission agrees with the rationale for a stretch factor put forward by EPCOR, NERA, AltaGas, the UCA and Calgary. The purpose of a stretch factor is to share between the companies and customers the immediate expected increase in productivity growth as companies transition from cost of service regulation to a PBR regime.

480. The ATCO companies and the CCA agreed that this reasoning forms part of the consideration when adding a stretch factor. As such, the Commission observes that this definition of stretch factor has been accepted by all parties to this proceeding, except Fortis.

481. In Fortis' view, a stretch factor should be added if a particular company were found to be less efficient than the industry as a whole. The ATCO companies and the CCA also noted that this rationale should be considered when determining the need for a stretch factor. However, as set out in Section 6.2 of this decision, the Commission does not wish to engage in this type of analysis for the purposes of PBR in Alberta because of the practical and theoretical problems associated with comparing efficiency levels among companies. Therefore, the Commission did not include the consideration of the companies' comparative levels of efficiency in its determination on the need for a stretch factor.

482. The Commission agrees with Dr. Weisman that the transition from cost of service regulation to PBR provides an opportunity to realize more easily-achieved efficiency gains (the

[579] Exhibit 98.02, ATCO Electric application, paragraph 45; Exhibit 99.01, ATCO Electric application, paragraph 41; Exhibit 529, AltaGas corrections and amendments to application, page 4; Exhibit 100.02, Fortis application, paragraphs 83-84; Exhibit 103.02, EPCOR application, paragraphs 84-85.

[580] Exhibit 103.02, EPCOR application, paragraphs 84-85; Exhibit 529, AltaGas corrections and amendments to application, page 4.

[581] Exhibit 98.02, Carpenter evidence, page 35; Exhibit 100.02, Fortis application, paragraph 85.

[582] Exhibit 195.01, AUC-NERA-12(d).

[583] Transcript, Volume 13, page 2579, lines 17-21; Transcript, Volume 17, page 3188, lines 13-19.

[584] Exhibit 629, Calgary argument, page 60.

[585] Exhibit 391.02, NERA second report, Table 3, page 30.

"low hanging fruit") due to increased incentives.[586] In the Commission's view, two issues are salient when considering the need for a stretch factor. The first issue is whether NERA's TFP estimate, on which the X factors for the Alberta companies are based, provides a good estimate for the productivity growth under PBR. As Dr. Cicchetti explained, in the case that an industry TFP trend is estimated using historical data that predominantly reflect the productivity experience under cost of service regulation, such a TFP target may need to be "stretched" to account for higher incentives under PBR.[587] However, it is not clear the extent to which NERA's data include both cost of service and PBR forms of regulation,[588] and there was no evidence on the record of this proceeding upon which to make such an adjustment.

483. The second issue to consider is whether there is a potential for the Alberta companies to collect the "low-hanging fruit" when transitioning from the current cost of service regulation to a PBR framework. In that regard, the Commission does not share Dr. Carpenter's view that the efficiency incentives under the current cost of service price setting framework in Alberta and PBR are going to be largely the same.

484. On the same topic, Fortis and the ATCO companies also argued that there will be no "low-hanging fruit" to pick under PBR because of the companies' strong productivity performance in recent years.[589] However, as the CCA pointed out, it is possible that the companies are unable to appraise the productivity gains that are achievable under PBR.[590] Dr. Weisman addressed this matter in an academic article that he co-authored as follows:

> With very limited potential rewards but significant disallowance risks, the traditional regulatory model strongly encourages the prudent use of tried-and-true operating practices and technologies. It thus provides very limited incentives, if not explicit disincentives, to look beyond the status quo to discover and employ new, innovative operating practices and technologies. This is why the provision of enhanced incentives can stimulate a discovery process that enables regulated firms to become more efficient than they previously knew how to be.[591]

485. The Commission observes that having analysed its recent experience under PBR, ENMAX also pointed to a number of efficiency improvements and cost-minimising measures that were realized since the transition to a regulatory regime with stronger efficiency incentives. Notably, ENMAX indicated that the company would not have undertaken these productivity initiatives under a traditional cost of service regulatory framework.[592]

486. Finally, the Commission notes that the companies characterized the inclusion of a stretch factor (or a lack thereof) as an alternative to an ESM. In this regard, the Commission agrees with NERA and the interveners that although there is some trade-off between an ESM and a stretch

586 Transcript, Volume 9, page 1766, lines 4-22.
587 Exhibit 103.05, Cicchetti evidence, pages 27-28.
588 Exhibit 299.02, Cronin and Motluk UCA evidence, page 79, footnote "c".
589 Exhibit 633, Fortis argument, paragraphs 144-146; Exhibit 631, ATCO Electric argument, paragraph 271; Exhibit 632, ATCO Gas argument, paragraph 296.
590 Exhibit 645, CCA reply argument, paragraph 47.
591 Exhibit 500.02, Weisman, Dennis L., and Pfeifenberger, Johannes P., *Efficiency as a Discovery Process: Why Enhanced Incentives Outperform Regulatory Mandates*, The Electricity Journal, January-February 2003, page 60.
592 Exhibit 297.01, ENMAX evidence, pages 16-18.

factor, they are not mutually exclusive.[593] This is demonstrated by the fact that a number of PBR plans in North America have both of these components.[594] Nevertheless, as set out in Section 10 of this decision, the Commission determined that an ESM should not be part of the companies' PBR plans. Accordingly, the inclusion of an ESM in the PBR plans of the companies cannot provide an additional justification for not imposing a stretch factor.

487. In light of the above considerations, the Commission agrees with EPCOR, AltaGas and the interveners that a stretch factor should be a part of the PBR plans for the Alberta companies.

6.5.2 Size of the stretch factor

488. Parties acknowledged that unlike TFP estimates, stretch factors are commonly set based upon regulatory judgment and evidence from other jurisdictions rather than on a theoretical basis.[595] However, in the parties' view, this judgement has to be informed by the empirical evidence to accord with best regulatory practices.[596]

489. In this respect, Dr. Cicchetti found informative the average level of the stretch factor assigned to electric distributors in Ontario. The Ontario Energy Board, in its third generation incentive regulation plan, set the stretch factors at 0.2 per cent, 0.4 per cent and 0.6 per cent for the most efficient, the average efficient and the least efficient distributors, respectively. The average of the stretch factors imposed by the Ontario Energy Board is 0.4 per cent. Dr. Cicchetti noted that this was also the stretch factor approved by the Commission for ENMAX in Decision 2009-035.[597] Given Dr. Cicchetti's view that his recommended O&M PFP was of a "conservative nature," and in conjunction with not having an ESM, EPCOR's expert recommended that the company's PBR plan include a stretch factor of 0.2 per cent that lies at the mid-point between a stretch factor of zero (Dr. Cicchetti's preferred value), and the 0.4 per cent assigned to ENMAX.[598]

490. The UCA also relied on the Ontario Energy Board's determination on the stretch factor. The UCA indicated that if the menu approach to the X factor is not adopted, it recommends stretch factors for the companies of between 0.2 and 0.6 per cent based on the current Ontario third generation PBR plan approach.[599]

491. AltaGas indicated that it is prepared to dispense with the ESM with the addition of a "modest stretch factor of between 0.1-0.2 per cent."[600] Dr. Schoech explained that this recommendation reflected his evaluation of how the X factor should change if an ESM is removed from the plan.[601]

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593 Exhibit 195.01, AUC-NERA-12(d); Transcript, Volume 13, page 2579, lines 17-21 (Dr. Lowry); Transcript, Volume 17, page 3188, lines 13-19 (Dr. Cronin); Exhibit 629, Calgary argument, page 60.
594 Exhibit 391.02, NERA second report, Table 3, page 30.
595 Exhibit 195.01, AUC-NERA-12(d); Transcript, Volume 9, page 1688, lines 18-23 (Dr. Schoech); Transcript, Volume 4, pages 776-778 (Dr. Carpenter).
596 Exhibit 103.05, Cicchetti evidence, page 28; Exhibit 634.02, UCA argument, paragraph 152; Transcript, Volume 13, page 2567, lines 1-10 (Dr. Lowry).
597 Decision 2009-035, paragraph 185.
598 Exhibit 103.05, Cicchetti evidence, pages 30-31.
599 Exhibit 634.02, UCA argument, paragraph 146.
600 Exhibit 529, AltaGas corrections and amendments to application, page 4.
601 Transcript, Volume 9, page 1689, lines 9-16.

492. PEG indicated that its research suggests that stretch factors for Alberta companies should lie in the range of 0.19 to 0.5 per cent. In developing its stretch factor recommendations, PEG examined regulatory precedent and noted that the average explicit stretch factor approved for PBR plans of energy companies with rate escalation mechanisms informed by productivity research is about 0.50 per cent.[602] In addition, PEG developed an incentive power model that estimates the typical cost performance improvements that will be achieved by companies under stylized regulatory systems. Calibrating this model for the circumstances of Alberta companies produced a stretch factor value of 0.19 per cent.[603] Based on the results of PEG's research, the CCA recommended that all companies be assigned the 0.19 per cent stretch factor that resulted from PEG's incentive power model.[604]

493. Based on the record of this proceeding, Calgary recommended that the stretch factor be in the range of 0.13 per cent to 0.5 per cent.[605]

494. Similar to the discussion about the size of the X factor, parties commented on whether the presence and the magnitude of a stretch factor have any effect on the incentives of PBR plans. EPCOR, AltaGas and the ATCO companies submitted that the strength of the incentives under a PBR plan is not tied to the magnitude of the X factor (including the stretch).[606] NERA and the CCA supported this view.[607]

495. In contrast, Calgary argued that inasmuch as the companies are going to be incented to find capital and operating efficiencies under PBR relative to the cost of service regulation, a stretch factor "will play a key role as an additional driver to achieve those efficiencies."[608] In a similar vein, the UCA submitted that a stretch factor should incent a company to "obtain maximum efficiency improvements."[609]

496. Fortis' evidence on this matter was contradictory. On one hand, Fortis argued that "the level of X, regardless of whether that level includes some notion of stretch, does not determine if the incentive properties of PBR grow or diminish. Whatever X is, or more accurately the result of I-X is, the incentive to attain and better that result exists."[610] On the other hand, Fortis submitted that "the imposition of a stretch factor [...] by its nature and effect could only increase the perceived incentive to cut costs in any available manner."[611]

602 Exhibit 307.01, PEG evidence, page 45.
603 Exhibit 307.01, PEG evidence, page 45 and Exhibit 478, PEG rebuttal evidence, page 24.
604 Exhibit 636, CCA argument, paragraph 106.
605 Exhibit 629, Calgary argument, page 33.
606 Exhibit 630.02, EPCOR argument, paragraph 86; Exhibit 628, AltaGas argument, page 34; Exhibit 631, ATCO Electric argument, paragraph 112; Exhibit 632, ATCO Gas argument, paragraph 122.
607 Transcript, Volume 1, page 117, lines 10-15 (NERA); Exhibit 636, CCA argument, paragraph 112.
608 Exhibit 641, Calgary reply argument, paragraph 132.
609 Exhibit 634.02, UCA argument, paragraph 157.
610 Exhibit 644, Fortis reply argument, paragraph 86.
611 Exhibit 633, Fortis argument, paragraph 157.

Commission findings

497. As parties pointed out, the determination of the size of a stretch factor is, to a large degree, based on a regulator's judgement and regulatory precedent and does not have a "definitive analytical source" like the TFP study represents.[612]

498. The UCA's experts recommended that the Commission assign stretch factors of between 0.2 and 0.6 per cent, similar to the Ontario Energy Board's determination in its third generation incentive regulation plans.[613] Dr. Cicchetti also found informative the average level of the stretch factor assigned to electric distributors in Ontario, and recommended a stretch factor of 0.2 per cent.[614] PEG proposed that stretch factors for Alberta companies should lie in the range of 0.19 to 0.5 per cent.[615] A similar range of 0.13 to 0.5 per cent was advocated by Calgary.[616] AltaGas recommended a stretch factor of 0.1 to 0.2 per cent.[617]

499. Taking into account the fact that the companies are moving from a cost of service regulatory framework to PBR, and being cognizant of the uncertainties associated with the change in regulatory framework, the Commission is taking a conservative approach to setting a stretch factor. Accordingly, the Commission considers that a stretch factor for Alberta companies should be on the lower end of the 0.2 to 0.6 per cent ranges recommended by PEG and the UCA's experts. The Commission observes that the CCA expressed its preference for a stretch amount on the lower side of the 0.19-0.5 per cent range recommended by its experts, PEG.[618] The Commission has considered the recommended stretch factors and finds a 0.2 per cent stretch amount to be reasonable. This stretch factor should apply to the companies' plans for the duration of the PBR term.

500. Finally, the Commission agrees with the parties who argued that while the size of a stretch factor affects a company's earnings, it has no influence on the incentives for the company to reduce costs.[619] Similar to a discussion in Section 6.1 of this decision, the Commission considers that PBR plans derive their incentives from the decoupling of a company's revenues from its costs as well as from the length of time between rate cases and not from the magnitude of the X factor (to which the stretch factor contributes).[620]

6.6 X factor proposals and the Commission determinations on the X factor

501. As discussed previously in this section, the X factor proposals in this proceeding reflected the parties' views as to the purpose of and approaches to determining the X factor, the relevant productivity estimates to use and the need for any adjustments, as well as considerations on the need for a stretch factor. Table 6-2 below shows that the parties' recommendations for an X factor are based on a variety of time periods and TFP indexes that the parties considered relevant.

612 Transcript, Volume 1, page 115, lines 6-19 (NERA). On this subject, see also Exhibit 103.05, Cicchetti evidence, page 28; Transcript, Volume 9, page 1688, lines 18-23 (Dr. Schoech); Transcript, Volume 4, pages 776-778 (Dr. Carpenter).
613 Exhibit 634.02, UCA argument, paragraph 146.
614 Exhibit 103.05, Cicchetti evidence, pages 30-32.
615 Exhibit 307.01, PEG evidence, page 45 and Exhibit 478, PEG rebuttal evidence, page 24.
616 Exhibit 629, Calgary argument, page 33.
617 Exhibit 628, AltaGas argument, page 33.
618 Exhibit 636, CCA argument, paragraph 106.
619 Exhibit 628, AltaGas argument, page 34;
620 Transcript, Volume 1, page 117, lines 10-15 (NERA); Exhibit 636, CCA argument, paragraph 112.

Table 6-2 Summary of the X factor proposals

	ATCO Electric/ ATCO Gas[621]	EPCOR[622]	Fortis[623]	AltaGas[624]	CCA[625]
Starting point	-0.28 to -1.09	-1.0	-1.0	-1.0 to -1.7	1.32 for gas companies 1.08 to 1.23 for electric companies
Productivity research relied upon	NERA's TFP	PFP based on NERA's data	Statistics Canada MFP index and NERA TFP	Statistics Canada MFP index and NERA TFP	PEG's TFP for gas companies NERA's TFP for electric companies
Time period	1994-2009 and 1999-2009	1999-2009	2000-2009	2000-2009	1996-2009 (PEG data) 1989-2007 (NERA data)
Adjustment for the U.S.-Canada productivity gap	-1.31 to -1.73	--	--	--	--
Stretch factor[626]	No	0.2	No	0.1 to 0.2	0.19
Proposed X factor (in per cent)	**-2.0**	**-1.0**	**-1.0**	**-1.3**	**1.08 to 1.32**

Note: Numbers do not add up due to a number of assumptions and qualifications that parties incorporated in their X factor proposals (for example, choice of a mid-point value for a range of X, application of a stretch factor only if an ESM was excluded from the plan, etc.).

502. Calgary recommended an X factor in the range of 1.0 to 1.7 per cent based on the results of NERA's and PEG's productivity studies.[627] As well, based on the record of this proceeding, Calgary recommended that the stretch factor be in the range of 0.13 per cent to 0.5 per cent.[628]

503. IPCAA did not make a specific recommendation on the X factor except to mention that a negative X factor unduly increases the risk of the companies over-earning.[629]

504. The UCA's experts, Dr. Cronin and Mr. Motluk, recommended using the X factor and ROE menu discussed in the Ontario Energy Board's *2000 Draft Rate Handbook*.[630] As set out in Section 6.2, the Commission did not accept the UCA's menu approach. The UCA also indicated that if the menu approach to the X factor is not adopted, it recommends stretch factors for the

621 Exhibit 98.02, Carpenter evidence, page 32, Table 3.
622 Exhibit 103.05 Cicchetti evidence, page 16.
623 Exhibit 100.02, Frayer evidence, pages 78-79.
624 Exhibit 110.01, Christensen Associates evidence, pages 13-15.
625 Exhibit 636, CCA argument, paragraphs 60-62.
626 Exhibit 631, ATCO Electric argument, paragraph 106; Exhibit 632, ATCO Gas argument, paragraph 116; Exhibit 630.02, EPCOR argument, paragraph 81; Exhibit 633, Fortis argument, paragraph 142; Exhibit 628, AltaGas argument, page 33; Exhibit 636, CCA argument, paragraph 106.
627 Exhibit 629, Calgary argument, page 24.
628 Exhibit 629, Calgary argument, page 33.
629 Exhibit 635, IPCAA argument, pages 2-3 and Exhibit 642, IPCAA reply argument, paragraphs 5-6.
630 http://www.oeb.gov.on.ca/documents/cases/RP-1999-0034/handbook0.html.

companies of between 0.2 and 0.6 per cent based on the current Ontario third generation PBR plan approach.[631]

Commission findings

505. As noted earlier in this section, the parties' X factor proposals were based on a variety of productivity indexes, approaches, and sample periods that they considered to be the most relevant in determining the X factor.

506. There was some discussion about whether the X factor to be used in a PBR plan necessarily has to be positive. The companies contended that there is nothing inherently wrong with a negative X factor. All companies proposed negative X factors in their respective PBR applications. Calgary did not agree with this conclusion and argued that a negative X factor does not provide the proper incentives to reduce costs.[632] IPCAA observed that a lower X factor would lead to a higher risk of company over-earning.[633]

507. On this issue, the Commission agrees with the companies' argument that, in theory, the X factor does not necessarily have to be always positive. As NERA's and EPCOR's experts explained during the hearing, a negative TFP (and the resulting X factor) just means that a particular industry grows more slowly in its productivity than the economy as a whole or that input costs are growing faster in the industry than in the economy.[634] Because the economy-wide productivity represents the average productivity of different industries comprising the national economy, some of the industries must be below average and some above. For instance, Dr. Makholm and Dr. Schoech pointed to the construction industry as an example of a sector with slower productivity growth.[635]

508. In Section 6.2 of this decision, the Commission reiterated its preference for an approach to setting the X factor based on the long-term rate of productivity growth in the industry. The Commission dismissed the alternative approaches to determining the X factor, such as the building blocks approach proposed by Fortis and the efficiency benchmarking and menu approaches proposed by the UCA.

509. In Section 6.3 of this decision, the Commission examined multiple aspects of the parties' TFP recommendations and determined that the results of NERA's TFP study represent a reasonable starting point for establishing a productivity estimate for Alberta electric and gas distribution companies. Based on the results of NERA's study, the Commission determined that a long-term industry TFP of 0.96 per cent represents a reasonable basis for determining the X factors to be used in the PBR plans of the electric and gas distribution companies. In this proceeding, parties discussed several potential adjustments to TFP to arrive at the X factor, some of which would have resulted in a negative X factor.

510. Specifically, NERA explained that the theory behind PBR plans may require an input price differential and a productivity differential adjustment to TFP if an output-based measure is used for the I factor.[636] However, the Commission explained in Section 6.4.1 above that because

631 Exhibit 634.02, UCA argument, paragraph 146.
632 Exhibit 629, Calgary argument, page 30.
633 Exhibit 304.01, IPCAA evidence, page 2.
634 Transcript, Volume 3, page 487, lines 20-22 and Volume 11, page 1987, line 17 to page 1988, line 11.
635 Transcript, Volume 3, page 488, lines 24-25, Volume 9, page 1678, lines 17-25.
636 Exhibit 461.02, AUC-NERA-17(a) and (b).

both components of the approved I factors can be considered input-based price indexes, no adjustment to TFP is required.

511. Additionally, Dr. Carpenter on behalf of the ATCO companies indicated that NERA's TFP analysis based on U.S. data needed to be adjusted for a productivity gap between the U.S. and Canadian economies.[637] Dr. Schoech on behalf of AltaGas also noted that this productivity gap warrants consideration.[638] As well, Dr. Carpenter and Dr. Cicchetti urged the Commission to consider the possible adjustment for the productivity performance of the Alberta economy when setting the X factor for the companies.[639] The Commission has reviewed the issue of productivity gap in Section 6.4.2 of this decision and determined that no adjustment to NERA's TFP is necessary to account for the differences in the economy-wide productivity growth between the U.S. and Canada, or Canada and Alberta.

512. The Commission has considered IPCAA's suggestion that a stretch factor be used to adjust for 2012 rates for historical over-earning. Give the approach the Commission has taken to the requested adjustments to going-in rates requested by the companies (see Section 3.4), the Commission will not make an adjustment to the stretch factor for that purpose. In Section 3.4, the Commission rejected adjustments to going-in rates to reflect selected actual results on 2012 because those adjustments could not be made without concurrently reviewing all actual results for 2012. The Commission will not assume what the results of such a review might be and seek to capture assumed 2012 productivity gains through an increased stretch factor.

513. Parties also discussed the effect on X of excluding all or part of capital from the I-X mechanism, as set out in Section 6.4.3. In that regard, because the Commission did not accept EPCOR's proposal to exclude capital from its PBR plan, no consideration of the partial productivity factors, of the type proposed by Dr. Cicchetti, is required in determining the X factor for the companies. With respect to the exclusion of only some capital, the Commission determined that no adjustments to TFP will be made during the PBR term to account for the possible exclusion of some capital from the I-X mechanism.

514. Based on the above, the Commission finds that no adjustments to the industry TFP growth rate are required when establishing the X factors for the companies. Accordingly, the Commission finds that the X factor to be used in the PBR plans of the electric and gas distribution companies prior to consideration of a stretch factor is 0.96 per cent.

515. Furthermore, as set out in Section 6.5 of this decision, the Commission determined that a stretch factor of 0.2 per cent will apply to the companies' PBR plans for the duration of the PBR term. Accordingly, the Commission finds that the total X factor for the electric and gas distribution companies, inclusive of a stretch factor, will be 1.16 per cent.

637 Transcript, Volume 4, pages 595-596.
638 Transcript, Volume 8, page 1414, lines 9-25.
639 Exhibit 98.02, Carpenter evidence, pages 33-34; Exhibit 233.01, AUC-ALLUTILITIES-EDTI-9(b).

7 Adjustment to rates outside of the I-X mechanism

7.1 Introduction

516. The Commission recognizes the need to make provision for recovery of a limited number of costs outside of the I-X mechanism. It is common for PBR plans to make special provision to reflect the cost impact of significant unforeseen events that are outside the ability of the regulated entity to control. Approved costs of this nature are recovered through a Z factor rate adjustment. In addition, the companies have proposed a capital factor for the recovery of certain specific capital project costs as well as Y factor rate adjustments to permit the flow through to customers of third party charges that are beyond the control of the companies, Commission directed costs, deferral accounts and certain other costs. This section will review each of the proposals to deal with costs outside of the I-X mechanism.

7.2 Z factors

517. A Z factor is ordinarily included in a PBR plan to provide for exogenous events. The Z factor allows for an adjustment to a company's rates to account for a significant financial impact (either positive or negative) of an event outside of the control of the company and for which the company has no other reasonable opportunity to recover the costs within the PBR formula.

518. The Commission considered the criteria for when the impact of an exogenous event would qualify for a Z factor adjustment to rates in Decision 2009-035 and accepted the following proposal put forward by Dr. Cronin:[640]

> With respect to exogenous events, the Commission considered the evaluation criteria proposed by Dr. Cronin, and has determined that the following criteria for an exogenous adjustment should be adopted.
>
> 1) The impact must be attributable to some event outside management's control;
> 2) The impact of the event must be material. It must have a significant influence on the operation of the utility otherwise the impact should be expensed or recognized as income, in the normal course of business;
> 3) The impact of the event should not have a significant influence on the inflation factor in the FBR formulas; and
> 4) All costs claimed as an exogenous adjustment must be prudently incurred.

519. Applying these criteria, if an exogenous event has an economy-wide impact, the cost of that impact will be reflected in and recovered through the I factor. Providing the company with additional revenues through a Z factor adjustment in circumstances where the event has economy-wide impacts would result in a double-counting of the impact of the exogenous event. The criteria adopted by the Commission in Decision 2009-035 also speak to the recovery of costs after they have been incurred and subsequently found by the Commission to have been prudently incurred.

520. All of the companies' proposed plans include Z factors and generally agreed with the continued use of the criteria established in Decision 2009-035.[641]

[640] Decision 2009-035, Section 9.3, paragraph 247, page 54.

521. NERA stated that generally PBR plans have Z factors to permit "[u]tilities to recover the costs of unforeseeable events with material impacts."[642] However, NERA also suggested that Z factors should be limited to exogenous factors that impact the entire industry "like a tax change, or a change in investment tax credit, or something else that would lift or lower the price that the industry would have to compete against if we were talking about a competitive business."[643] A Z factor should not be used to address the impact of an exogenous event which affected the company alone.[644]

522. All interveners accepted that Z factors are a necessary component of a PBR plan.[645] The primary concern of interveners was to limit the use of Z factors by having clearly defined criteria and appropriate materiality thresholds. The UCA suggested the continued use of the criteria from Decision 2009-035 because those criteria were working well in the ENMAX plan, and there is no evidence to the contrary.[646] Calgary proposed an alternative set of criteria that were substantially similar to the four criteria adopted in Decision 2009-035, and added a criterion requiring the company to promptly report the event when first discovered.[647]

Commission findings

523. The Commission considers it necessary to include a Z factor in the PBR plan to account for the impact of material exogenous events for which the company has no other reasonable cost recovery or refund mechanism within the PBR plan. The Commission continues to support the criteria established in Decision 2009-035 to determine if the impacts of an exogenous event qualify for Z factor treatment, with one clarification. The Commission considers that for the negative impact of an exogenous event to qualify for cost recovery, the extent of the impact must, by necessary implication, be unforeseen prior to the occurrence of the event. This criterion is necessary to distinguish the cost impacts of exogenous events that are not foreseeable from the cost impacts of other events that are beyond the company's control but are foreseeable and therefore may qualify for Y factor treatment as discussed in Section 7.4 below. In Decision 2009-035 the Commission also made a distinction between exogenous adjustments and flow-through items by stating:[648]

> With respect to flow-through rate adjustments, the Commission considers that flow-through rate adjustments arise from cost elements that are not unforeseen one time events. Flow-through items arise in the normal course of business, but are such that the company has no control over them.

641 Exhibit 628.01, AltaGas argument, Section 9.1, page 47; Exhibit 630.02, EPCOR argument, Section 9.1, paragraph 159, page 59; Exhibit 631.02, ATCO Electric argument, Section 9.2, paragraph 205, page 54; Exhibit 632.01, ATCO Gas argument, Section 9.2, paragraph 214, page 70; Exhibit 100.02, Fortis application, Section 7, paragraph 118, page 34.

642 Exhibit 391.02, NERA second report, Section IV-C-3, paragraph 71, page 35.

643 Transcript, Dr. Makholm, Volume 1, page 179, lines 5-9.

644 Transcript, Dr. Makholm, Volume 1, pages 179-180.

645 Exhibit 634.02, UCA argument, Section 9.1, paragraph 209, page 38; Exhibit 636.02, CCA argument, Section 9.1, paragraph 145, page 59; Exhibit 942.01, IPCAA reply argument, Section 9.0, paragraph 12, page 2; Exhibit 629.01, Calgary argument, Section 9.1, page 42.

646 Exhibit 634.02, UCA argument, Section 9.2, paragraph 214, page 38.

647 Exhibit 629.01, Calgary argument, Section 9.2, page 43.

648 Decision 2009-035, Section 9.3, paragraph 251, page 55.

524. Accordingly, the Commission considers that the following criteria will apply when evaluating whether the impact of an exogenous event qualifies for Z factor treatment:

(1) The impact must be attributable to some event outside management's control.
(2) The impact of the event must be material. It must have a significant influence on the operation of the company otherwise the impact should be expensed or recognized as income, in the normal course of business.
(3) The impact of the event should not have a significant influence on the inflation factor in the PBR formulas.
(4) All costs claimed as an exogenous adjustment must be prudently incurred.
(5) The impact of the event was unforeseen.

525. The Commission considers that all of the above criteria must be met in order for an item to qualify for a Z factor rate adjustment.

526. Inclusion of a Z factor based on clearly defined criteria is consistent with the Commission's PBR principles. The Commission observes that when an exogenous event occurs within a competitive industry that is not generally felt within the economy as a whole, the companies within the industry will generally adjust their prices in response to the event. A Z factor will permit the regulated distribution companies in Alberta to do the same. The Commission notes that Dr. Makholm agreed with this characterization.[649]

527. With respect to the opinion of Dr. Makholm that a Z factor should not be available to deal with the impacts of a company specific exogenous factor because it would not parallel competitive markets, the Commission notes that no such restriction was imposed in Decision 2009-035. Further, the Commission considers that allowing a company specific exogenous factor to potentially qualify for Z factor treatment is in keeping with the fourth Commission PBR principle which states that the design of PBR plans should recognize the unique circumstances of each regulated company. Also, allowing recovery of the costs of a company specific exogenous event is consistent with providing the company with a reasonable opportunity to recover its prudently incurred costs. Accordingly, the impact of company specific exogenous events will not be excluded from consideration for Z factor treatment.

528. The Commission considers that Z factors should be symmetrical in that they should apply to exogenous events with both additional costs that the company needs to recover and also reductions to costs that need to be refunded to customers. The Commission agrees with the CCA and considers it necessary to allow the Commission and interveners to apply for Z factor adjustments to rates where circumstances warrant.

7.2.1 Z factor materiality

529. Materiality may be considered on an event-by-event basis or cumulatively. Under the ENMAX FBR plan, materiality is evaluated on an event-by-event basis.[650] Most of the companies in this proceeding proposed that materiality be evaluated on a cumulative basis. That is, if the sum of the effects of a number of exogenous events in a year would have a material impact on the company, they should be considered as though they were one event for Z factor purposes.

[649] Transcript, Dr. Makholm, Volume 1, page 179, lines 5-9.
[650] Decision 2009-035, Section 9.3, paragraph 231, page 51.

530. The following table sets out the materiality thresholds of the Z factor as approved for ENMAX in Decision 2009-035 and as proposed by each of the companies in this proceeding:

Table 7-1 Summary of companies Z factor materiality proposals

	ENMAX[651]	AltaGas[652]	ATCO Electric[653]	ATCO Gas[654]	EPCOR[655]	Fortis[656]
Threshold	$1.0 million	Variable (approx. $0.2 million)[657]	$0.5 million	$0.5 million	$1.0 million distribution $0.5 million transmission	$0.5 million
Basis for determining the threshold	Size of revenue requirements	Annual impact on ROE ≥ +/- 25 basis points	Rule 005 variance threshold criteria	Rule 005 variance threshold criteria	Rule 005 variance threshold criteria	Rule 005 variance threshold criteria[658]
Cumulative	No	Yes	Yes	Yes	Yes	No

531. Concerns were raised by interveners over having materiality thresholds set too low, particularly when materiality is measured on a cumulative basis, because it allows companies to qualify for Z factor adjustments on too frequent a basis. It was suggested by Calgary's witness, Mr. Matwichuk that AUC Rule 005[659] is not the appropriate source for finding the criteria to determine the materiality thresholds for Z factor adjustments, and if comparisons to PBR plans in other jurisdictions are made, a higher threshold would be used.[660] The UCA suggested that the materiality thresholds should be established by taking 0.25 per cent of net assets, which would result in significantly higher threshold levels.[661]

532. The CCA stated that it is appropriate to address the materiality of Z factors on an individual event basis in order to achieve consistency with the process established in Decision 2009-035.[662] Dr. Lowry submitted that having low materiality thresholds that could result in frequent Z factor applications is contrary to the spirit of PBR. Dr. Lowry stated the following at the oral hearing:

> I can tell you too that, you know, in some jurisdictions, including the Ontario Energy Board, they're not very encouraging to the utilities to come in even for Z factor proposals as violating the spirit of the PBR.[663]

Commission findings

533. Setting a Z factor threshold too low invites parties to submit applications on too frequent a basis, and undermines the regulatory efficiency that PBR seeks to achieve. Setting a Z factor

651 Decision 2009-035, Section 9.3, paragraph 248, page 54.
652 Exhibit 110.01, AltaGas application, Section 7.2, paragraph 84, page 26.
653 Exhibit 98.02, ATCO Electric application, Section 7, paragraph 206, page 7-1.
654 Exhibit 99.01, ATCO Gas application, Section 2.6, paragraph 112, page 40.
655 Exhibit 103.02, EPCOR application, Section 2.3.4.1, paragraphs 134-140.
656 Exhibit 219.02, AUC-ALLUTILITIES-FAI-19.
657 Transcript, Mr. Mantei, Volume 8, page 1487.
658 Transcript, Mr. Lorimer, Volume 12, page 2238.
659 Rule 005: *Annual Reporting Requirements of Financial and Operational Results* (Rule 005).
660 Transcript, Mr. Matwichuk, Volume 15, page 2953.
661 Exhibit 634.02, UCA argument, Section 9.2, paragraph 217, page 39.
662 Exhibit 636.01, CCA argument, Section 9.3.1, paragraph 152, page 61.
663 Transcript, Dr. Lowry, Volume 14, page 2673.

threshold too high may limit a company's reasonable opportunity to recover prudently incurred costs, or conversely may prevent customers from realizing the benefit of a reduction in costs.

534. Exogenous events may occur during the PBR term but by definition they are exceptional occurrences which may either add costs to, or remove costs from, the provision of utility service. Additionally, not all events beyond the control of the company will qualify under other Z factor criteria, thereby further reducing the number of already rare events that could result in a rate adjustment outside of the I-X mechanism. Given the exceptional nature of a qualifying exogenous event and the equally exceptional measure of authorizing a recovery outside of the I-X mechanism, the Commission considers that the PBR principles require a relatively high threshold and that this threshold should apply to each event unless otherwise permitted in exceptional circumstances.

535. The Commission considers that the approach to establishing a materiality threshold based on the impact to ROE as proposed by AltaGas is reasonable. However, the Commission finds that the materiality threshold should be higher. In order to establish the threshold the Commission has calculated the impact on ROE that the dollar threshold established for ENMAX represented in 2006 (going-in rates). Accordingly, the Commission establishes the threshold as the dollar value of a 40 basis point change in ROE on an after tax basis calculated on the company's equity used to determine the revenue requirement on which going-in rates were established (2012). This dollar amount threshold is to be escalated by I-X annually. The companies are directed to calculate and file the 2012 threshold amount along with supporting calculations in the compliance filing to this proceeding.

7.2.2 Process for considering a Z factor application

536. Having separate Z factor applications from the PBR annual filings may result in a need for more applications, and therefore may increase the administrative burden. However, if separate Z factor applications can be completed prior to the PBR annual filings, the annual filing process will not be complicated with potentially contentious Z factor items.

537. The companies generally agreed that addressing Z factors as part of the annual PBR rate adjustment filing process, rather than through a separate regulatory process, would be in the best interests of regulatory efficiency.[664] Fortis raised concerns that a Z factor application may require a protracted review, and as such, including Z factors as part of the annual PBR rate adjustment filing process may not be optimal.[665]

538. The UCA stated that "[t]o maximize regulatory efficiency, Z factor applications should be made at the same time as deferral and other PBR filings."[666] Calgary addressed the issue of how to process Z factor applications when it included a new criterion for Z factors that "the utility will be required to report promptly at the first discovery of an event and then apply for disposition of the accumulated savings or costs at the time of annual reporting."[667] In addition,

[664] Exhibit 632.01, ATCO Gas argument, Section 9.3, paragraph 219, page 71; Exhibit 631.01, ATCO Electric argument, Section 9.3, paragraph 210, page 55; Exhibit 630.02, EPCOR argument, Section 9.3, paragraph 168, page 63; Exhibit 628.01, AltaGas argument, Section 9.3, page 48.
[665] Exhibit 633.01, Fortis argument, Section 9.3, paragraph 180, page 83.
[666] Exhibit 634.02, UCA argument, Section 9.3, paragraph 220, page 40.
[667] Exhibit 629.01, Calgary argument, Section 9.2, page 43.

the CCA stated that "the utilities and stakeholders should both be eligible to file Z factor proposals."[668]

539. The Commission outlined the process for Z factor applications in Decision 2009-035.

> In order to ensure fairness to all stakeholders, EPC or other parties are directed to notify the Commission of all proposed exogenous adjustments as soon as possible after the event that gives rise to them is identified. The Commission also directs that the impact of any proposed exogenous adjustment be initially captured in a separate account pending a ruling from the Commission. The impact of any proposed adjustment is to be measured from the time the event occurred. The disposition of the account would follow the Commission's ruling on the proposed adjustment.[669]

Commission findings

540. The Commission finds that the process established in Decision 2009-035 is satisfactory. Accordingly, companies are directed to notify the Commission of all proposed exogenous adjustments as soon as possible after the event that gives rise to them is identified. Further, Z factor applications should be submitted as soon as possible after the costs associated with the exogenous event have been incurred or the savings have been realized.

541. A party may file a Z factor application at any time. However, in order to minimize the number of rate adjustments during the year, unless otherwise permitted, the Commission directs that Z factor rate adjustment applications be filed as part of the annual PBR rate adjustment filing. Please see Section 15.1.2 for a more detailed explanation of how the inclusion of Z factor amounts will be included in the annual PBR rate adjustment filing process.

542. In Decision 2009-035 the Commission recognized that some Z factors may result from changes in circumstances that carry forward into future periods.

> The Commission recognizes that, in some cases, a "Z" adjustment for an extraordinary event will be transitory and will not be subject to the I minus X adjustment. In other cases, the extraordinary event may require a "Z" adjustment that is subject to the I minus X adjustment going forward. The Commission will make this determination on a case by case basis.[670]

543. The Commission recognizes that some approved Z factor applications may generate costs or savings that can be fully recovered or refunded over a single year or portion thereof while other events will generate costs or savings requiring treatment over a longer term. The nature of the required Z factor rate adjustment will be considered by the Commission on a case-by-case basis.

7.3 Capital factors

7.3.1 Need for a capital factor

544. All of the companies argued that they are experiencing some cost pressures on capital expenditures that will require special treatment under PBR. There was some agreement among NERA and the experts representing the companies and interveners that certain types of unusual

[668] Exhibit 636.01, CCA argument, Section 9.1, paragraph 145, page 59.
[669] Decision 2009-035, Section 9.3, paragraph 250, page 55.
[670] Decision 2009-035, Section 9.3, paragraph 249, page 54.

capital expenditures may require capital factors as part of a PBR plan to provide for sources of revenue in addition to the revenue generated by the I-X mechanism.

545. The companies offered several reasons why capital factors are required, including the costs being outside of the control of the company, the costs to build capital being significantly higher than historic norms, the need to build specific large projects, and high growth rates of the system. Another reason that was cited by several of the companies was a surge in replacement activities requiring an unusually high level of capital expenditures during the PBR term.[671] Because of the long term nature of utility assets, the cycles in which the companies purchase capital assets are much longer than the length of the PBR term. The evidence and testimony indicated that installation of large amounts of facilities during high growth periods in the past creates an echo effect when those facilities come to the end of their useful lives and must be replaced in current dollars with large replacement projects. Consequently, the companies submitted that if a utility is at a stage where it must invest more than the historical rate of capital asset growth or capital asset replacement assumed in the X factor, a special capital factor may be required.[672]

546. Experts representing the interveners acknowledged that under some circumstances special treatment of capital may be required, although most of the interveners took issue with the extent to which special capital treatment had been proposed.[673] There was concern expressed that double-counting may occur in circumstances where the companies should be able to recover the capital expenditures through the I-X mechanism, but are also provided with relief through a capital factor.[674] The double-counting may occur because the I-X mechanism already provides funding for capital projects and the addition of a capital factor outside of the formula would provide that funding again. The CCA also argued that companies have some flexibility in the timing of replacement expenditures without affecting safety or reliability, so utilities may have the ability to defer some replacement capital expenditures instead of seeking a capital factor adjustment.[675]

547. One of the concerns with approving capital factors is that the efficiency incentives created by a PBR plan may be reduced because the incentives to find efficiencies by substitution among various types of inputs (expenses and capital) may be lessened. In an exchange with Commission counsel, Dr. Makholm addressed how significant of a concern this is.

> Q. If the Commission was to accept company proposals that excluded significant capital components, does that mean that the X factor, if it was the same as your TFP estimate, would be wrong?
>
> A. DR. MAKHOLM: It wouldn't mean that the TFP growth number that we've calculated, that's then used for the X factor, would be wrong. It would call into question

671 Exhibit 636.01, CCA argument, Section 8.1, paragraph 117, page 46; Exhibit 630.02, EPCOR argument, Section 8.2, paragraph 97, page 36; Exhibit 631.01, ATCO Electric argument, Section 8.3, paragraph 146, page 40; Exhibit 628.01, AltaGas argument, Section 5.4, page 32.

672 Exhibit 98.02, ATCO Electric application, Section 5, paragraph 46, page 5-1; Exhibit 99.01, ATCO Gas application, Section 2.4, paragraph 45, page 20; Exhibit 628.01, AltaGas argument, Section 8.2, pages 38 to 39; Exhibit 630.02, EPCOR argument, Section 8.2, paragraph 96, page 35

673 Exhibit 629.01, Calgary argument, Section 8.3, page 40, Exhibit 636.01, CCA argument, Section 8.2, paragraph 122, page 49, Exhibit 634.02, UCA argument, Section 8.3, paragraph 182, page 33.

674 Transcript, Dr. Makholm, Volume 1, page 162.

675 Exhibit 636.01, CCA argument, Section 8.1, paragraph 118, page 46.

> the basis for the PBR regime itself because, as you just recounted as our answer, the use of a total factor productivity study embraces the idea that different factors of production are substitutable and the substitution of different factors of production over time constitute one of the areas of TFP growth.
>
> The theory upon which this kind of PBR formula is based doesn't apply to a kind of regime that would only target, for instance, O&M costs. So in that respect, the formula is wrong. The application of PBR in this context, drawing upon a competitive paradigm, is wrong; not the calculation of the TFP growth itself.[676]

548. The UCA agreed with NERA's opinion with respect to the impact on PBR incentives that results from the use of capital factors.

> The creation of a flow-through shifts the risk to customers and is in violation of AUC Principle 1, that a PBR plan should incent behavior similar to a competitive market. For the examples listed, the factors affecting the forecast are not beyond the utility's control, in fact the decision to proceed is entirely a utility management decision. Management must weigh the costs and benefits of all options, including the status quo, and decide on a course of action.[213] If there is flow-through treatment, the incentive to examine alternatives will be eliminated.[677]
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> [213] Exhibit 0300.02, Evidence of Russ Bell at A26.

Commission findings

549. The Commission recognizes that the TFP study used to determine the X factor adopted by the Commission in this proceeding measures the rate of productivity change of the distribution industry over time necessarily reflecting input costs including the types of capital expenditures and all of the types of year to year fluctuations in the need for capital referred to by the companies. Nevertheless, the Commission acknowledges that there are circumstances in which a PBR plan would need to provide for revenues in addition to the revenues generated by the I-X mechanism in order to provide for some necessary capital expenditures. The way in which this is accomplished is through a capital factor (K factor) in the PBR plan. The capital proposals of the companies were all quite different. Some companies asked for considerably more capital to be treated outside of the I-X mechanism than others.

550. The Commission shares the concerns raised by NERA and interveners that a capital factor must be carefully designed in order to maintain the efficiency incentives of PBR, and also to avoid double-counting. At issue are the types and levels of capital expenditures that can reasonably be expected to be recovered through the I-X mechanism. The Commission finds that a mechanism that permits the recovery of specific types of capital outside of the I-X mechanism should be included in a PBR plan. In the sections of this decision that follow, the Commission addresses these issues by adopting a capital factor that, to the greatest extent possible, seeks to maintain the incentive properties of PBR and avoids double-counting.

7.3.2 Methodologies for addressing capital

551. A number of alternatives for a capital factor were explored during the proceeding. These included determining the average rate of capital growth in the TFP study and providing for

[676] Transcript, Volume 1, page 143.
[677] Exhibit 634.02, UCA argument, Section 8.3, paragraph 196, pages 35-36.

capital in addition to that amount as required, modifying the X factor in consideration of a need for higher capital spending, excluding all capital from going-in rates and the I-X mechanism, and providing compensation for capital needs outside of the normal course of the company's operations by way of a capital tracker.

7.3.2.1 The average rate of capital growth in the TFP study

552. Dr. Carpenter approached the issue of identifying the amount of capital expenditures that the I-X mechanism can support by proposing that the capital factor be calibrated by comparing the capital requirements of the company to a benchmark level established by the median level of growth in plant observed in the utilities in the NERA TFP study.[678] Dr. Carpenter examined capital investment information about the companies in NERA's TFP study to estimate that the median level of annual growth in plant was 4.5 per cent over the relevant time period of the NERA TFP study that he used to determine the X factor he proposed.[679]

553. There were several issues identified with respect to the approach suggested by Dr. Carpenter.

554. Dr. Makholm commented on Dr. Carpenter's analysis as follows:

> Simple trends from past data series not having to do with our type of TFP growth study is what he is proposing as a way of creating -- I can't remember whether it was his Y or K factor, I'm not sure, one of those two. I think in our evidence and in responses to data request responses -- data requests, we drew a line between those types of things and the specific ring fenced engineering-based justified capital expenditures that consumed our 15 or 20 minutes before the break. For our purposes, at least for my purposes, using that kind of trend to project capital input over the course of a PBR plan is not very reliable. I wouldn't do it.[680]

555. NERA also stated:

> Under this logic additional adjustments would need to be made to account for the fact that the regulated firm's labor input and material input may be growing at different trend rates than the 72 utilities in the NERA sample. If, however, adjustments are made to each input to account for the differences between the trend rates of the regulated firm and the 72 utilities the result would be that regulated prices would be tied to actual productivity changes of the regulated firm rather than the industry's productivity. This means that the PBR incentive properties would be similar to the incentive properties under cost of service regulation. An important linchpin of performance based regulation and price cap regulation is that the X factor represents the productivity of the industry and not the productivity of the regulated company.[681]

556. NERA also calculated a different capital growth rate of 1.32 per cent for 1972 to 2009 based on the capital index used in its TFP study.[682] NERA stated "[w]e deal with capital quantity inputs measured in a very idiosyncratic way with one hoss shay techniques, and I think what you'll find in response to AUC NERA 15 that we're trying to dissuade anybody from taking the

[678] Transcript, Dr. Carpenter, Volume 4, page 643.
[679] Transcript, Dr. Carpenter, Volume 4, page 643.
[680] Transcript, Dr. Makholm, Volume 1, page 155.
[681] Exhibit 195.01, AUC-NERA-8(a).
[682] Exhibit 195.01, AUC-NERA-8(b).

trends in capital quantity input we use to arrive at TFP growth analysis from being used to project new investments in whatever over the course of PBR planning."[683] Dr. Ros went on to explain:

> Can I just add productivity growth is the change in outputs and change in the three different inputs. So what Dr. Carpenter has observed is investment, net investment, which is not an input in the TFP study. And your question doesn't follow in the sense you're not mentioning anything about what's going on with output or other input at the same time. But in addition to that, it seems to be implying that in order for a TFP [PBR] plan to be effective you have to track exactly the type of changes that the utilities are likely to experience over the next five years, which does away with the incentive properties of performance-based ratemaking.[684]

557. Dr. Lowry also explained the impact that customer growth has on capital, and that customer growth for the Alberta utilities is more rapid than it is for the typical utility.[685] In theory, a company could be experiencing significantly higher capital growth than 4.5 per cent, but if the capital expenditures are required to add new customers and additional load to the system, there would be offsetting impacts to outputs in the calculation of TFP, and productivity growth would not necessarily be significantly impacted.[686]

558. ATCO Electric employed Dr. Carpenter's analysis to develop the ATCO K factor proposal. That proposal was based on a three plank approach. The first plank was intended to include the level of capital expenditures the I-X mechanism can support, which ATCO Electric determined to be 4.9 per cent annual growth.[687] The second plank was comprised of the remaining amount of capital growth in its current four year capital forecast, which was to be funded by the ATCO K factor. ATCO K factor programs were selected on the basis that they were stable and predictable and could be forecast for a four year period. The third plank was comprised of capital projects that do not occur on a routine basis and, therefore, could not be accurately forecasted. The end result of the three plank approach was that ATCO Electric prepared an overall capital forecast, and proposed a method by which that forecast could be recovered in the PBR plan. Mr. Freedman explained the ATCO Electric approach as follows:

> When we did our forecast of the rate base growth on its own, that showed us that we were closer to 10 percent. So when we were designing the planks, we were just looking at that. We tested the results and the outcomes of all of that afterwards, after we designed the planks to see it was in. What the results were going to give us with these planks was still in the area of reasonableness, and we showed those results in section 16 of the application.[688]

559. Mr. Freedman further explained in a discussion with Commission counsel how the determination of the 4.9 per cent that could be funded from application of the I-X mechanism was determined:

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683 Transcript, Dr. Makholm, Volume 1, page 154.
684 Transcript, Dr. Ros, Volume 1, page 157.
685 Transcript, Dr. Lowry, Volume 13, page 2605.
686 Exhibit 307.01, CCA evidence of PEG, Section 4.1, page 61.
687 Dr. Carpenter had calculated a 4.5 per cent median annual investment growth rate for the companies in the NERA TFP study. ATCO Electric chose 4.9 per cent for its first plank because of the types of capital projects it could identify.
688 Transcript, Mr. Freedman, Volume 7, page 1263.

> So when we looked at the capital maintenance programs and the programs that fell within that definition, we looked at the dollar impact of that. We looked at the results that were arising from that through -- and we would see that through -- in Section 16 of our application. And given that the 4.5 percent was part of a range and that was considered. We could have gone more aggressive but we didn't want to -- we didn't want to gray it up with putting some programs in that may be not quite as stable and predictable and readily factorable. So it could have been more aggressive to get it down to the 4 1/2 percent, but looking at the results that were being generated with the overall plan, ATCO Electric believed that it could put forward the programs as we've selected.
> Q. The 4.9 fell out of that analysis; is that right?
> A. MR. FREEDMAN: Correct.[689]

560. Under its approach ATCO Electric forecasted a total amount of revenue requirement first, and then developed rates (in this case using a PBR formula) to ensure that it is collecting the amount of revenue requirement needed to fund the forecasted amounts over the PBR term.

561. With particular reference to the ATCO Electric K factor, the UCA pointed out that the requirement for business cases for capital spending would have been subject to extensive review under cost of service regulation, and that the same level of testing would be required under PBR if the ATCO Electric K factor approach were used.[690]

Commission findings

562. The Commission finds that the evidence of capital investment growth of the companies included in NERA's total factor productivity study can not be used to determine the average amount of capital expenditures that could be recovered through the I-X mechanism because the Commission agrees with Dr. Makholm's, Dr. Ros' and Dr. Lowry's criticisms that such an approach does not account for the variability of capital investments and other inputs in relation to outputs from year to year. In addition, the Commission agrees with Dr. Makholm's observation that a simple trend analysis of average capital investment is an unreliable predictor of the amount of capital that can be funded through the I-X mechanism. Accordingly, the Commission rejects Dr. Carpenter's approach to determining the amount of capital growth that should be recovered through the I-X mechanism.

563. Because the ATCO Electric approach forecasts the total amount of capital revenue requirement over the PBR term to ensure that it is collecting the amount of revenue needed to fund its forecast capital expenditures, the Commission considers that the adoption of the ATCO Electric proposal would amount to retaining cost of service regulation for all capital but with a four year forecast. The Commission would not only be required to test the projects that comprise the ATCO Electric K factor, but it would also need to test the projects covered by the 4.9 per cent. If the projects that make up the 4.9 per cent were not tested, ATCO Electric could select which projects and types of capital expenditures should be included in the 4.9 per cent thereby avoiding scrutiny of possible double-counting of costs already in the K factor. If the Commission were to direct ATCO Electric to provide details for all capital projects including those captured by the 4.9 per cent, it would represent a return to cost of service regulation for all capital for a four year forecast term, reducing the efficiency incentives that PBR creates and failing to reduce the regulatory burden.

[689] Transcript, Mr. Freedman, Volume 4, pages 685-686.
[690] Exhibit 634.02, UCA argument, Section 8.2, paragraph 180, page 32.

7.3.2.2 Modifying the X factor to accommodate the need for higher capital spending

564. There was some discussion that that the X factor could be modified to provide sufficient revenues to cover a higher level of capital investment growth than provided for in the I-X mechanism.

565. In the view of Dr. Carpenter, when developing the X factor from a TFP study it is necessary to take into account the forecasted investment needs of the specific company for which the PBR plan is being designed.[691] As such, Dr. Carpenter appeared to suggest that a smaller X factor was required for the companies that expect a higher than usual level of capital expenditures during the PBR term. At the same time, Dr. Carpenter explained that he did not recommend this adjustment, since the ATCO companies proposed to deal with higher than usual capital expenditures by means of their K factor:

> DR. CARPENTER: ...And I think we also would have to take into account whether or not unusually high [capital expenditures] growth requirements over the plan term would require an X adjustment. Now, in ATCO's case X is not being adjusted for [capital expenditures]. Instead in ATCO Electric's case a K factor has been employed to deal with that issue.
> Q. And in the absence of the K factor you would be recommending an adjustment to the X in addition to the productivity gap?
> A. DR. CARPENTER: One may have to, yes.[692]

566. Fortis and AltaGas stated that if the Commission were to decide not to include capital flow-through factors in the PBR formula, it would be necessary to adjust the X factor to allow the financing of these capital projects under the I-X mechanism.[693] The CCA stated that it would be open to experimentation with such an approach because it has been used in PBR plan designs in other jurisdictions.[694]

567. At the same time, AltaGas acknowledged that this approach would be a "British-style building blocks" approach to developing the X factor, and would unnecessarily complicate the derivation of the formula.[695] Similar to the ATCO Companies, EPCOR, Fortis and AltaGas preferred to deal with unusual capital expenditures by way of flow-through factors, and not by adjusting the X factor.[696]

568. NERA explained that under this approach, the X factor is calculated as the value that would set the customer rates at a level to recover the company's cost of service revenue requirement over a forecast period.[697] In Dr. Makholm's view, forecasts that extend as far into the future as the length of a PBR term become vague, and undermine the effectiveness of a PBR plan.[698] Dr. Makholm concluded:

691 Exhibit 476.01, Carpenter rebuttal evidence, page 10.
692 Transcript, Volume 3, page 592, lines 4-13.
693 Exhibit 628, AltaGas argument, page 32 and Exhibit 633, Fortis argument, paragraph 138.
694 Exhibit 636.01, CCA argument, Section 8.4, paragraph 136, page 55
695 Exhibit 628, AltaGas argument, page 32 and Exhibit 247.01, AUC-ALLUTILITIES-AUI-7(a).
696 Exhibit 233.01, AUC-ALLUTILITIES-EDTI-7(b); Exhibit 628, AltaGas argument, page 32 and Exhibit 633, Fortis argument, paragraph 139.
697 Exhibit 391.02, NERA second report, pages 27-28.
698 Transcript, Volume 1, page 160 and Volume 3, page 502, lines 9-17.

> I think as I've -- as we have tried to distinguish between adjustments to X -- that is, Y factors or K factors -- cognizant of what goes on in Britain, where X is a true-up measure for long-term forecasts, it's our conclusion that it is better to leave X to do what X is designed in North America to do, which is to reflect total factor productivity growth and let other elements of ratemaking reflect unusual or special-case or needed capital expenditures.[699]

Commission findings

569. The companies acknowledged that any attempt to adjust the X factor for the investment needs of a specific company requires a detailed forecast of a company's capital expenditures and the associated revenue requirement, billing determinants, and even inflation over the PBR term.[700] As NERA and AltaGas pointed out, this approach essentially amounts to adopting the building blocks method employed by the regulators in the U.K.[701]

570. In Section 6.2 above, the Commission rejected the use of a building blocks approach and restated its preference for an approach to setting the X factor based on the long term average rate of productivity growth in the industry. Accordingly, the Commission finds that the X factor should not include any adjustments to deal with company-specific forecast capital expenditures.

7.3.2.3 Exclude all capital from going-in rates and the I-X mechanism

571. Due to the complexities of establishing what capital spending should be included and excluded from the I-X mechanism, EPCOR recommended that, in its case, all capital should be excluded from going-in rates and consequently not be subject to the I-X mechanism. Such an approach essentially splits the revenue requirement of the company so that capital is dealt with in a traditional cost of service manner, and the remainder of the revenue requirement is subject to the I-X mechanism and other PBR formula variables. The K factor proposed by EPCOR encompasses all capital.

572. EPCOR was unique amongst the companies in its proposal to exclude all capital from the I-X mechanism. The other companies proposed a limited number of capital factors that were more targeted at specific types of projects. EPCOR argued that it is faced with unique circumstances in that it must replace a more significant portion of its system during the PBR term.[702] While EPCOR considered the options of including all capital within the I-X mechanism and using capital trackers for special circumstances, EPCOR concluded that the regulatory burden would be significantly reduced if it excluded all of its capital from the I-X mechanism because there are too many projects that have complex interrelationships requiring capital tracker treatment.[703]

573. NERA expressed the view that the negative impact on incentives that excluding a significant portion of capital has is significant enough to bring into question whether PBR should

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[699] Transcript, Volume 1, page 119, lines 9-17.
[700] Exhibit 233.01, AUC-ALLUTILITIES-EDTI-7(a), Exhibit 201.01, AUC-ALLUTILITIES-AE-7(a), Exhibit 633, Fortis argument, paragraph 78.
[701] Exhibit 247.01 AUC-ALLUTILITIES-AUI-7(a).
[702] Exhibit 630.02, EPCOR argument, Section 8.2.1, paragraphs 105-107, pages 39-41.
[703] Exhibit 630.02, EPCOR argument, Section 8.2.1, paragraph 102, page 38.

be allowed to proceed. Several interveners supported the opinion of NERA.[704] Dr. Makholm addressed the issue saying:

> It would call into question the basis for the PBR regime itself because, as you just recounted as our answer, the use of a total factor productivity study embraces the idea that different factors of production are substitutable and the substitution of different factors of production over time constitute one of the areas of TFP growth.[705]

Commission findings

574. The Commission has previously considered the EPCOR approach for the complete exclusion of capital from its PBR plan, and rejected this approach for the reasons set out in Section 2.3. The Commission is concerned that excluding all capital or a large portion of the company's capital expenditures from going-in rates and the I-X mechanism would significantly dampen the efficiency incentives of a PBR plan.

7.3.2.4 Capital trackers

575. In its second report and in response to the capital factor proposals made by the companies, NERA referred the Commission to the growing use by some U.S. regulators of capital trackers that allow a regulated firm to track and begin to recover the costs associated with certain capital projects more quickly and more efficiently than in a normal rate case.[706] NERA indicated that capital trackers are "used in various situations where the typical regulatory rate case provides an inadequate mechanism to adjust rates in response to increased investment in infrastructure."[707] NERA indicated that capital trackers could be used in conjunction with a PBR plan to deal with certain special capital requirements. NERA described the purpose and use of capital trackers as follows:

> Capital trackers are used to recover the costs of a classified, pre-approved set of infrastructure investments. The tracker does not include all infrastructure investments, rather only infrastructure investments that meet the classifications set at the on-set of the tracker; all other infrastructure investments are recovered in the company's next rate case proceeding. A "qualified investment" is an investment that meets the pre-set conditions for inclusion in the asset tracker. Typically, the proposed accounts included in a capital tracker go beyond the scope of routine investments required to support existing infrastructure. Qualified investments are specific, non-routine investments recovered outside of the normal rate case proceeding.[708]

576. NERA favoured an approach that did not rely on calculating the dollar amount of capital that could or could not be accommodated by the I-X mechanism. Rather, it focused on the nature of the projects and whether those projects are consistent with the past practices of the company. NERA said that unusual projects may need special capital treatment, but "because everybody's rates are based on their own books and records in base rates, and if the company has been doing

704 Exhibit 629.01, Calgary argument, Section 8.6, page 41; Exhibit 636.01, CCA argument, Section 8.6, paragraph 138, page 56; Exhibit 634.02, UCA argument, Section 8.2, paragraph 175, page 31.
705 Transcript, Dr. Makholm, Volume 1, page 143.
706 Exhibit 391.02, NERA second report, Section 4, paragraphs 86-91, pages 41-43.
707 Exhibit 391.02, NERA second report, Section 4, paragraph 88, page 42.
708 Exhibit 391.02, NERA second report, Section 4, paragraph 90, page 43.

whatever it is that we're describing consistently over the course of many years, it's in their base rates, and hence the base rates ought to be able to reflect that capital expense."[709]

577. NERA described the capital tracker mechanism by stating that "the basic idea of a capital tracker is to recover the costs of qualified infrastructure investments incurred between rate cases through an asset tracker."[710] This means that once a capital project has been identified as a capital tracker the costs associated with the project are tracked and a cost of service revenue requirement calculation is performed for the project to determine the amount of revenue the company requires. That revenue requirement is collected by the company through rate adjustments outside of the I-X mechanism.

578. When asked why a capital tracker is any better than any other exclusion of capital from the I-X mechanism, and in particular a PBR plan which excludes capital entirely, Dr. Makholm stated:

> That's a fair question. Capital trackers are there because there's not an administrative and practical way in the commission's judgment to deal with certain kinds of aged infrastructure any other way than to have a rate base case. That issue of capital affects PBR jurisdictions as much as it affects any other jurisdiction.
>
> The difference between that kind of targeted engineering-based approach to particular kinds of aged infrastructure or lumpy prospective capital and the proposals from one of the utilities to do an O&M only rate cap plan I think are large and manifest.
>
> One takes a piece of prospective capital expense and subjects it to the microscope of justification and engineering so that the public is well served through the efficient replacement of infrastructure that the public needs. That is specific and targeted.
>
> The other type, which is apply PBR only to O&M, is neither specific nor targeted, it's general. And for practical purposes, I think observers can distinguish between those two kinds of methods of regulation.[711]

579. NERA stated that one of the main benefits of the capital tracker approach is that, by limiting the trackers to a few very specific items it maintains the incentive properties of PBR for most of the plan, while still recognizing that some relief may be required for companies to handle lumpy investments.[712]

580. The capital tracker approach was supported by several other parties.[713] In addition, most of the parties agreed that a capital tracker approach is reasonable for inclusion in a PBR plan. Even EPCOR, which discarded capital trackers as a viable option for its own plan, acknowledged that the incentive properties of capital trackers are superior to the exclusion of all capital from the I-X mechanism it proposed.[714]

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709 Transcript, Volume 1, page 162.
710 Exhibit 391.02, NERA second report, Section 4, paragraph 89, page 42.
711 Transcript, Dr. Makholm, Volume 1, pages 146-147.
712 Transcript, Dr. Makholm, Volume 1, pages 146-147.
713 Transcript, Dr. Weisman, Volume 10, pages 1906-1907; Transcript, Mr. Camfield, Volume 8, page 1457; Transcript, Ms. Frayer, Volume 12, page 2395; Transcript, Dr. Lowry, Volume 13, page 2627; Transcript, Mr. Bell, Volume 18, pages 3274-3275.
714 Exhibit 646.02, EPCOR reply argument, Section 8.1, paragraph 106, page 33.

581. While agreeing with the underlying premise for a capital tracker, ATCO Electric expressed its concern about the inability to determine the amount of capital that can be funded outside of the I-X mechanism.[715] EPCOR raised a related concern when it argued that its analysis had shown that a capital tracker approach "proved unworkable due to the complex interrelationships between baseline capital and new capital and the lack of any credible basis upon which to separate the two in a well-defined, defensible manner."[716] EPCOR concluded that the issues around splitting capital costs were substantial enough to warrant excluding all capital from the I-X mechanism.

582. ATCO Electric stated that the capital tracker approach is an alternative it could work with.

> However, if ATCO Electric's approach is not acceptable to the Commission then a well defined tracker mechanism that encompasses ATCO Electric's programs currently included in ATCO Electric's K factor would be an alternative that ATCO Electric could work with.[717]

583. Some companies proposed to deal with some capital expenditures through capital Y factors on the basis that the level of expenditures was so significant that the I-X mechanism could not handle them. The ATCO Electric and ATCO Gas material-capital-unique-in-nature Y factors and the AltaGas AMR (automated meter reading) implementation Y factor are examples of this. There was some recognition by ATCO Gas,[718] ATCO Electric[719] and AltaGas,[720] that their proposed Y factor capital costs may not meet the typical criteria for assessing capital trackers or Y factors but they argued that the significance of the costs is so substantial that the projects can be justified on the basis of materiality alone given that there is an assumption that the projects are in the public interest.

584. The UCA recommended that these types of capital Y factors not be allowed on the basis that "[t]he creation of a flow-through shifts the risk to customers and is in violation of AUC Principle 1, that a PBR plan should incent behavior similar to a competitive market."[721] The CCA also expressed concern with the impact of these capital Y factors on the incentive properties of PBR, saying that "to the extent these costs are recovered as incurred, the de-linking of revenues from costs, being one of the foundations of any PBR plan, is weakened."[722]

585. Several companies requested capital Y factors for capital expenditures that are outside of the control of the company. Examples of this are the Fortis externally driven capital Y factor,[723] the ATCO Electric distribution contributions to transmission,[724] and the ATCO Gas transmission driven costs.[725] One of the arguments used to support the flow-through treatment of these particular capital costs was that utility companies have unique obligations to undertake such

715 Exhibit 631.01, ATCO Electric argument, Section 8.2, paragraph 125, page 35.
716 Exhibit 630.02, EPCOR argument, Section 8.2.1, paragraph 102, page 38.
717 Exhibit 631.01, ATCO Electric argument, paragraph 163, page 49.
718 Exhibit 632.01, ATCO Gas argument, Section 8.3, paragraph 190, page 61.
719 Exhibit 211.01, NERA-AE-17.
720 Exhibit 247.01, AUC-ALLUTILITIES-AUI-10.
721 Exhibit 634.02, UCA argument, Section 8.3, paragraphs 193 and 196, page 35.
722 Exhibit 636.01, CCA argument, Section 10.2.1, paragraph 167, page 69.
723 Exhibit 100.02, Fortis application, Section 6.2, paragraphs 103-105, pages 29-30.
724 Exhibit 98.02, ATCO Electric application, Section 6, paragraphs 104-112, pages 6-6 to 6-7.
725 Exhibit 99.01, ATCO Gas application, Section 2.5.2.2, paragraphs 93-102, pages 34-36.

projects that a competitive firm would not encounter. Fortis explained that "as a result of its obligation to serve, FortisAlberta does not have the discretion to decline or delay such expenditures, unlike competitive firms."[726]

Commission findings

586. The Commission has determined that a mechanism to fund certain capital-related costs outside of the I-X mechanism through a capital factor is required. In the preceding sections the Commission has generally rejected the methodologies proposed by the companies for addressing this requirement. The Commission considers that the potential erosion of the incentive properties of PBR that arise from adopting the approaches to capital factors proposed by the companies are significant enough to warrant the use of the capital tracker approach to address special capital funding requirements. The Commission considers that the targeted criteria-based nature of a capital tracker limits the number of projects that are outside of the I-X mechanism, and as a result, the incentive properties of PBR are preserved to the greatest extent possible. Therefore, the Commission accepts that the use of capital trackers, as proposed by NERA and as recognized by several other parties as a viable option, is the best of the alternatives proposed for dealing with capital expenditures outside of the I-X mechanism. Accordingly, the Commission will include a capital tracker mechanism in the PBR plans.

587. A capital tracker mechanism in a PBR plan is warranted in circumstances where the company can demonstrate that a necessary capital replacement project or capital project required by an external party cannot reasonably be expected to be recovered through the I-X mechanism. The Commission concludes that a structured criteria-based approach provides the most objective method for assessing whether projects qualify as capital trackers.

588. Many of the proposals for capital factors in the form of K factors, the AltaGas MP factor, or Y factored capital expenditures are PBR plan variables that attempt to track the costs and corresponding revenue requirement of specific assets, and recover the revenue requirement outside of the I-X mechanism. Regardless of what a company originally called the capital factor variable, as long as the variable isolates the revenue requirement impact of the underlying qualifying assets (including depreciation, return on equity, cost of debt and income tax) to be incorporated into the PBR plan outside of the I-X mechanism, the factor is in the nature of a capital tracker and will be considered and tested as a capital tracker. The non-specific K factor proposed by EPCOR[727] is an obvious exception because it does not involve tracking specific capital assets. For consistency, all capital trackers will be recovered through a K factor variable in the PBR formula for all companies.

589. Dr. Makholm discussed the types of considerations the Commission should take into account in establishing the criteria for a capital tracker:

> Q Well, the incentive formula will produce a certain revenue stream and the incentives that result from the imposition of this regime will create savings through efficiencies through the company. So the effective revenue that a utility would have would be a mixture of the I minus X portion of the formula; it would be a function of growth in revenues, growth in customers, growth in revenues; a function of depreciation that has fallen off -- assets that are fully depreciated but yet the depreciation expense remains in rates. It would also be a function of all the efficiencies that can be achieved throughout

726 Exhibit 474.01, Fortis rebuttal evidence, Section 2.5, paragraph 76, page 14.
727 Exhibit 630.02, EPCOR argument, Section 8.1, paragraph 91, page 34.

the term. How does a regulator know when a ring fenced proposal for a tracker comes to them whether or not there's sufficient resources available through the operation of the PBR formula with all the incentives that are instilled through to it to cover the costs of that and how will they know when there isn't enough revenue to cover that?

A. DR. MAKHOLM: They'll know if the company can make good enough case that the derogation from a plan inherent in employing a tracker is genuine and worth the effort. And we have seen cases where that is the case, and one of them, a prime one, is cast iron pipe.

Q. We're all kind of dancing around the same question, but it's a very interesting discussion, so I'll try to advance it a bit further. So assume with me for a moment that a utility is able to put together the state of the art capital tracker application, ring fenced, engineering data to support it, and it has been doing that same type of activity for many years.

A. DR. MAKHOLM: Well, why then would they require a tracker if they've been doing that activity for many years? If they have been -- I don't mean to butt in, but if they have done, then that activity will be reflected in their base rates.

Q. And that's -- okay. So, in other words, it has to be something unusual, out of the normal course of the utility as opposed to what the industry group that formed the basis for the TFP study that carries on?

A. DR. MAKHOLM: Well, sure. Because everybody's rates are based on their own books and records in base rates, and if the company has been doing whatever it is that we're describing consistently over the course of many years, it's in their base rates, and hence the base rates ought to be able to reflect that capital expense. It's what isn't in base rates that's idiosyncratic and out of phase and deferred and lumpy that the formula wouldn't be able to cover, and that's the dividing line for derogating from a formula that's supposed to cover everything, is whether or not you decide by looking that there's a certain category of costs or a certain practical nature of any particular company's activities that lead it to conclude and convince the Commission that a straight-forward formula of the RPI minus X plus Z variety won't do.[728]

590. In an exchange with Calgary's counsel, Dr. Makholm clarified several qualifying criteria for capital trackers:[729]

Q. There was discussion yesterday with Mr. McNulty that these kinds of trackers would not – would not be or were not included in the base or the going-in rates; correct?
A. DR. MAKHOLM: Yes.
Q. And that they were idiosyncratic in nature. Yes?
A. DR. MAKHOLM: Yes.
Q. That, again referencing the between-rate-cases aspects, they were outside -- or were incurred outside of a rate case proceeding. Yes?
A. DR. MAKHOLM: Yes.
Q. They were incurred outside the ordinary course of business of the utility?
A. DR. MAKHOLM: Yes.

728 Transcript, Volume 1, pages 160-163.
729 Transcript, Volume 2, page 339.

> Q. And they were incurred outside of or unrelated to past practices of the utility. Did I hear that right yesterday?
> A. DR. MAKHOLM: Yes.
> Q. Are there any others that I've missed?
> A. DR. MAKHOLM: No, not that I can recall.

591. In addition to the criteria identified above, there was some discussion of other characteristics that should be exhibited by projects that qualify for special capital treatment. For projects to be considered atypical, NERA stated that the costs associated with the projects should be substantial.[730] NERA also suggested that any projects should be supported by an engineering analysis.[731] In addition, as stated by the CCA "investments to meet customer and load growth trigger revenue growth and are largely self-funding,"[732] therefore these projects should not be eligible for capital tracker treatment if they result in customer and load growth because the incremental costs should be funded by other features of the PBR formula.

592. Based on the foregoing, the Commission adopts the following criteria for capital trackers:

(1) The project must be outside of the normal course of the company's ongoing operations.

(2) Ordinarily the project must be for replacement of existing capital assets or undertaking the project must be required by an external party.

(3) The project must have a material effect on the company's finances.

593. The Commission considers that the party recommending the capital tracker must demonstrate that all of the criteria have been satisfied in order for a capital project to receive consideration as a capital tracker. Accordingly, the Commission rejects the proposals to permit capital factors on the basis of materiality alone or on the basis that the project is externally driven alone, as was suggested by some of the companies proposing capital-related Y factors.

The project must be outside of the normal course of the company's ongoing operations

594. The first criterion is required to avoid double-counting between capital related costs that should be funded by way of a capital tracker and those that should be funded through the I-X mechanism. This criterion is also required to ensure that capital tracker projects are of sufficient importance that the company's ability to provide utility service at adequate levels would be compromised if the expenditures are not undertaken. Projects that do not carry this level of importance are likely subject to a reasonable level of management discretion, therefore allowing special treatment for this type of capital would eliminate the incentive for the company to examine all alternatives.[733] Therefore, this criterion would require that an engineering study be filed to justify the level of capital expenditures being proposed. That is, the company must demonstrate that the capital expenditures are required to prevent deterioration in service quality and safety, and that service quality and safety cannot be maintained by continuing with O&M and capital spending at levels that are not substantially different from historical levels. The company will also be required to demonstrate that the capital project could not have been undertaken in the past as part of a prudent capital maintenance and replacement program.

[730] Transcript, Dr. Makholm, Volume 1, page 171.
[731] Transcript, Dr. Makholm, Volume 1, page 147.
[732] Exhibit 636.01, CCA argument, Section 8.1, paragraph 117, page 46.
[733] Exhibit 634.02, UCA argument, Section 8.3, paragraph 196, page 36.

Ordinarily the project must be for replacement of existing capital assets or undertaking the project must be required by an external party

595. The second criterion generally limits the scope of eligible capital projects to those required for replacement of aged infrastructure that has come to the end of its useful life and those that are required by third parties, such as projects ordered by government agencies. It excludes projects required to accommodate customer or demand growth because a certain amount of capital growth is expected to occur as the system grows and system growth generates new sources of revenue that offset the costs of the new capital. The new sources of revenue can come in the form of increased customers and load growth,[734] and also through contributions in aid of construction as prescribed by maximum investment level (MIL) policies.[735]

596. NERA stated that just because a capital expenditure is externally driven is not sufficient to justify a separate capital factor for it. Dr. Makholm identified the fact that even though it may be externally driven, the items may already be covered by the I-X mechanism if a similar level of costs is reflected in going-in rates.

> I would have to agree only on the condition that I've stated before, which is they're not reflected in the normal course of business reflected in the revenue requirement. They are specific and unusual enough to carve out and deal with separately. You have to appreciate our perspective, that for a distribution company everything is externally driven in one fashion or another. It's driven by the public services need for lights, and that the quantity of service that a utility provides isn't up to it; it's up to what the public requires, because all these distributors are set up to serve all-comers. So just saying externally driven doesn't do it for me. You would have to say externally driven, unusual enough not to be reflected in the cost of service as a going-forward exercise, and capable of being carved out as a limited feature so as not to disrupt unnecessarily the basic features of the PBR plan, which is to provide some regulatory lag and incentives.[736]

597. The UCA stated that externally driven capital expenditures do not meet the test of a capital tracker on the basis that the projects are not limited in nature, externally driven capital is included in going-in rates, the projects are not outside the ordinary course of utility business, and externally driven capital is related to the past practices of a utility.[737]

598. The CCA argued that supplemental capital expenditure funding may be required if it can be substantiated by solid evidence for investments “due to events beyond the utility’s control such as highway relocations or the construction of a new transmission line.”[738]

599. The Commission is aware that some of the capital costs for distribution utilities would otherwise not be required were it not for the activities of transmission or system operator entities or other external parties, and that the costs to the distribution utilities can be material and can vary significantly from year-to-year. Due to a company’s obligation to provide service there is no opportunity for the company to turn down the project on the basis that company could not recover its costs because the project may not meet the capital tracker criteria, and therefore the company would be exposed to not receiving adequate compensation for undertaking the project.

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[734] Exhibit 636.01, CCA argument, Section 8.1, paragraph 117, page 46.
[735] Transcript, Volume 7, page 1310.
[736] Transcript, Dr. Makholm, Volume 2, page 330.
[737] Exhibit 634.02, UCA argument, Section 8.3, paragraph 199, page 36.
[738] Exhibit 636.01, CCA argument, Section 8.2, paragraph 122, page 50

600. Fortis indicated that the expenditures included in its Y factor for externally driven capital arise in the normal course of business.[739] While the obligations to perform the work exist for the companies, the Commission considers that a company must demonstrate that such costs are significantly different than historical trends to qualify for capital tracker treatment, otherwise there is a likelihood for double-counting.

The project must have a material effect on the company's finances

601. The third criterion is required to limit the use of capital trackers. NERA stated that the costs associated with capital trackers should be substantial due to the regulatory burden associated with the administration of the tracker.[740] The Commission considers that a utility may be frequently undertaking a number of small projects that may have the appearance of being atypical. However, the fact that the utility is undertaking a certain level of atypical projects on a consistent basis may result in that level of small unique projects being considered to be in the normal course of operations. The Commission also considers that it would not be suitable to group together several dissimilar projects into a single large project to give the appearance of materiality. However, a number of smaller related items required as part of a larger project might qualify for capital tracker treatment.

7.3.3 Implementation of capital trackers

7.3.3.1 Isolation of capital trackers from other fixed assets

602. The inclusion of capital trackers in the PBR plan presents a potential for double-counting if capital costs that should be funded by the I-X mechanism are also funded by the revenue provided through a capital tracker. To avoid the possibility of double-counting some parties proposed a method whereby the revenue requirement associated with historical costs (depreciation, return on capital and taxes) are removed from the going-in rates, thereby eliminating any possible impact of dealing with the capital tracker-related expenditures outside of the I-X mechanism.

603. Some of the proposed PBR plans proposed to isolate historical capital costs associated with certain capital expenditures for the PBR term. Fortis proposed to isolate the historical AESO contributions from going-in rates, and then take the revenue requirement associated with all AESO contributions to calculate that portion of its externally driven capital expenditures Y factor.[741] Fortis stated that it is not able to isolate the historical costs for the other types of capital expenditures that comprise the externally driven capital expenditures Y factor, due to the level of detail available in its asset ledgers.[742] AltaGas proposed a different form of adjustment to its major projects factor with the same underlying purpose, to avoid double-counting. To achieve this AltaGas proposed a reduction to the annual major projects factor calculation to exclude the revenue requirement impact associated with similar capital expenditures made between December 31, 2009 and December 31, 2012.[743]

604. Because capital trackers typically represent a surge in capital spending that will be followed by a period of slower than average capital spending, and therefore the company's future revenue requirements should be less than they otherwise would have been in the absence of the

[739] Exhibit 474.01, Fortis rebuttal evidence, Section 2.5, paragraph 73, page 14.
[740] Transcript, Dr. Makholm, Volume 1, page 171.
[741] Exhibit 100.02, Fortis application, Section 6.2, paragraph 105, page 30.
[742] Exhibit 222.17, CCA-FAI-8(b).
[743] Exhibit 110.01, AltaGas application, Section 6.0, paragraph 69, page 19.

capital tracker, there were some concerns raised over how long the projects should remain outside of the I-X mechanism. PEG suggested that if certain capital expenditures are excluded from the I-X mechanism in a PBR plan, then those capital expenditures should remain outside of the I-X mechanism in the next rate plan as well. PEG explained:

> The Y factoring of capex cost is sometimes advocated on the grounds that the capex in question is a one-time surge. To the extent that this is true, it should also be noted that the productivity growth of the company should accelerate once the surge is complete because the surge will cause the rate base to grow more slowly after it is completed. If PBR should accommodate a revenue surge now to help finance the capex, it should then reflect the slower revenue (requirement) growth that later results and thereby improve customer finances. One way to accomplish this is to have the costs of capex (e.g. depreciation and return) that are excluded from one indexing plan be recovered outside of indexing in the next rate plan as well.[744]

605. Other parties generally objected to this suggestion by PEG because it creates unnecessary complexity in subsequent PBR plans. These parties recommended that, the capital expenditures associated with the capital tracker should be included with the rest of rate base in the rebasing process.[745]

Commission findings

606. The Commission considers that the reduction to the capital tracker to eliminate the impact of similar expenditures included in going-in rates as proposed in the AltaGas major projects factor may be a reasonable method for addressing the issue of double-counting. However, the merits of any such proposal would need to be assessed as part of the approval process for individual capital trackers.

607. The Commission does not find that a company should remove the impact of historical costs associated with expenditures similar in nature to approved capital trackers from going-in rates as proposed by Fortis for its AESO contributions. The Commission considers that it is necessary to maintain the incentive properties of PBR to the greatest extent possible by keeping the maximum amount of capital expenditures subject to the I-X mechanism.

608. The Commission accepts the arguments that the complexity of isolating certain capital expenditures in perpetuity beyond the PBR term outweighs the benefits suggested by PEG. Therefore, the Commission requires that the revenue requirement impact of the capital tracker expenditures be recorded outside of the I-X mechanism only during the course of the current PBR term.

7.3.3.2 Method for determining capital tracker amounts

609. Some parties have objected to the use of capital trackers on the basis that they result in too much regulatory burden.[746] On the other hand, capital trackers are a reasonable method for retaining the efficiency incentive properties of PBR as discussed in Section 7.3.2.4.

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[744] Exhibit 307.01, PEG evidence, Section 2.2.6, page 24.

[745] Exhibit 631.01, ATCO Electric argument, Section 8.5, paragraphs 201-202, page 53; Exhibit 632.01, ATCO Gas argument, Section 8.5, paragraph 212, page 68; Exhibit 628.01, AltaGas argument, Section 8.5, page 43.

[746] Exhibit 646.02, EPCOR reply argument, Section 8.1, paragraph 108, page 34; Exhibit 634.02, UCA argument, Section 8.4, paragraph 205, page 37.

Dr. Makholm stated that if a capital tracker is required to address the legitimate concerns of a company, the negative impact on administrative burden should not be a concern.[747] Given the criteria outlined for capital trackers in Section 7.3.2.4 it is clear that a relatively rigorous testing of capital trackers must occur.

610. Some of the companies have suggested that it would be administratively more efficient to not review the forecast for capital factors on an annual basis. The ATCO Electric K factor proposed to use forecasts at the outset of the PBR term that remain unchanged for the duration of the plan.[748] ATCO Electric and ATCO Gas suggested that not truing up the forecasts for capital factors introduces some superior incentive properties by allowing the companies to beat their approved forecasts.[749] The CCA supported the use of fixed forecasts on the basis that fixing the forecast would provide strong capital expenditure containment incentives. However, the CCA acknowledged that there would be an incentive for the companies to exaggerate their capital needs and therefore there would need to be a strong evidentiary record supporting the capital forecasts.[750]

611. Some of the companies suggested that their capital factors be reforecast periodically. Examples of this include the ATCO material-investments-unique-in-nature,[751] the Fortis externally-driven-capital Y factor,[752] and the AltaGas system reliability projects component of the major projects factor.[753] AltaGas also proposed a formulaic annual adjustment mechanism for the system safety projects component of its major projects factor.[754]

612. Another approach proposed to avoid the regulatory burden of reviewing forecasts is to only deal with capital trackers on a retrospective basis after the company has decided to proceed with the project and has made the capital expenditure. ATCO Gas proposed that this approach be used for its urban mains replacement (UMR) Y factor project.[755] Dr. Makholm suggested that a capital tracker should be based on items that are known and measurable rather than general forecasts to ensure that the tracker is specifically targeted.[756] Dr. Makholm suggested that if a tracker is limited to costs that are truly required to be recovered outside of the I-X mechanism, the efficiency incentives of a PBR formula will be lost.[757] Dr. Makholm explained one of the shortcomings of relying on capital forecasts is the incentive to overstate capital forecasts in saying:

> The other way is to find a formula that perhaps has incentives that are like the incentives in the UK that I described, that leave rise five years from now to the commission feeling that it's been hoodwinked with forecasts that haven't turned out to be what was actually spent. They may not have been hoodwinked, but how are you going to tell?[758]

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[747] Transcript, Dr. Makholm, Volume 3, page 506.
[748] Exhibit 476.01, ATCO Electric rebuttal evidence, paragraph 39, page 13.
[749] Transcript, Ms. Wilson, Volume 7, page 1280.
[750] Exhibit 636.01, CCA argument, Section 8.3.2, paragraph 127, page 52.
[751] Transcript, Ms. Wilson, Volume 4, page 759.
[752] Transcript, Mr. Delaney, Volume 11, pages 2152-2154.
[753] Exhibit 110.01, AltaGas application, Section 6.3, paragraph 78, page 22.
[754] Exhibit 110.01, AltaGas application, Section 6.2, paragraphs 75-76, pages 21-22.
[755] Exhibit 389.01, ATCO Gas application updates, Section 2.3, paragraph 12, page 7.
[756] Transcript, Dr. Makholm, Volume 1, page 175.
[757] Transcript, Dr. Makholm, Volume 1, page 168.
[758] Transcript, Dr. Makholm, Volume 3, page 506.

Commission findings

613. The Commission acknowledges that a reduction in the frequency of capital reviews would achieve a reduction in administrative burden. In addition, the Commission acknowledges that the use of long term forecasts as proposed by ATCO Electric for its K factor does create some efficiency incentives. However, in the absence of a true-up, the Commission considers the incentives for a company to exaggerate its capital needs, as identified by the CCA, to be a major drawback to such an approach, and accordingly on that basis long term forecasts will not be used for capital trackers.

614. The Commission recognizes that superior efficiency incentives would be created if the companies were required to make capital investment decisions and undertake the investment prior to applying for recovery of their costs by way of a capital tracker. However, the Commission recognizes that parties and the Commission have very little experience with capital trackers and, therefore, will not require that this approach be used by the companies during the first PBR term.

615. Accordingly, unless a company chooses to undertake investment prior to applying for recovery of its costs by way of a capital tracker, the company will be expected to provide a forecast with its capital tracker application. The company will only be permitted to collect the forecast amounts for the capital tracker on an interim basis, and a true-up to the actual amount of the capital tracker will occur after the capital expenditures have been made. As a result, these companies will still have some efficiency incentives due to the risk of regulatory disallowances in the true-up process if expenditures are not prudently incurred.

7.3.4 Commission findings on the capital factors proposed by the companies

616. The capital projects proposed by the companies for capital factor or capital Y factor treatment may or may not satisfy the criteria for a capital tracker established by the Commission in this decision. Neither the companies nor other parties have had the opportunity to evaluate whether these projects satisfy the Commission’s criteria. Accordingly, the Commission makes no finding as to whether any of the capital projects proposed by the companies satisfy the Commission’s criteria. The companies may file, as separate applications at the time of their compliance filing on November 2, 2012, applications for approval of specific 2013 projects as capital trackers, including projects that were included in their PBR filings. The companies need not re-file the information already on the record of this proceeding with respect to those capital projects included in their PBR filings. The companies may specifically refer to the record of this proceeding and supplement that information with additional information or explanations to address the Commission’s capital tracker criteria

7.4 Y factor

617. In a PBR plan, Y factor costs are those costs that do not qualify for capital tracker treatment or Z factor treatment and that the Commission considers should be directly recovered from customers or refunded to them. Y factor costs in turn, could either be costs the company is required to pay to a third party (such as the AESO) or other Commission-approved costs incurred by the company for flow through to customers.

618. In Decision 2009-035 the Commission approved the flow-through of certain costs incurred by ENMAX along with the established collection of these costs outside the I-X mechanism. The Commission stated:[759]

> With respect to flow-through rate adjustments, the Commission considers that flow-through rate adjustments arise from cost elements that are not unforeseen one time events. Flow-through items arise in the normal course of business, but are such that the company has no control over them. The Commission approves the following three items for flow-through treatment.
>
> - SAS rates in the distribution tariff
> - TAC Deferral Account
> - AESO load settlement costs

619. In Decision 2010-146[760] (the ENMAX compliance filing decision), the Commission approved the addition of the Commission's own administrative fee as a flow-through cost. Although not considered material, the Commission found it to be similar in nature to other flow-through amounts approved by the Commission.[761]

620. As a result of these criteria, under the ENMAX FBR plan, a cost might qualify to be collected as a flow-through cost outside of the I-X mechanism if the amount was foreseeable and regularly incurred in the normal course of business but the quantum and requirement to pay the cost was outside of the control of management. In addition, the amounts approved by the Commission should be material.

621. In this proceeding, each of the companies proposed the treatment of several accounts outside of the I-X mechanism. The companies designated all of these costs as Y factors. The Y factor accounts proposed by the companies substantially exceeded the number of flow-through items approved in Decision 2009-035.

622. The proposed Y factor costs included existing flow-through accounts similar to those approved in the ENMAX decision, deferral accounts that had been approved under cost of service rate regulation, new deferral accounts and unusual capital expenditures. The companies argued that all of these costs should be recovered as Y factors because these costs are highly volatile, recurring or have previously been approved by the Commission for flow-through treatment. More importantly, all of these costs were considered by the companies to be outside the funding capacity of the I-X mechanism.

623. In its review of these companies' Y factor proposals, NERA commented that the inclusion of a comprehensive set of deferral accounts was unusual in PBR plans,[762] and that an

759 Decision 2009-035, Section 9.3, paragraph 251, page 55.
760 Decision 2010-146: ENMAX Power Corporation, Decision 2009-035 Formula Based Ratemaking Compliance Application, Application No. 1604999, Proceeding ID. 191, April 22, 2010
761 Decision 2010-146, Section 9.1.1, paragraph s 97-100, page 16.
762 Exhibit 391.02, NERA second report, Section IV-D-2, paragraph 83, page 40.

overly broad set of Y factor accounts reduces efficiency incentives under PBR.[763] Interveners generally agreed with NERA's observations.

624. The CCA noted "that some utilities (most notably AE and AG) propose excessive use of Y factors."[764] The UCA recommended "that the ENMAX type flow-through items, like system access charges, AESO load settlement costs, transmission costs from upstream pipelines, the UCA assessment, the AUC assessment should continue as flow-through"[765] but objected to the wide use of deferral accounts. The UCA submitted that the Commission should not approve a number of the proposed Y factor accounts, stating that the Commission has previously ruled that deferral accounts should be approved only when they are demonstrably necessary.[766] IPCAA generally supported the recommendations of the UCA with respect to Y factors.[767] Calgary suggested that the ATCO Gas PBR plan should "retain the integrity of PBR through the reliance on the (I – X) mechanism, to the greatest extent possible."[768]

625. All of the companies commented that changes to their risk profiles could occur if deferral accounts that exist under cost of service were not continued as Y factors under PBR.[769] IPCAA also identified this as a factor to be considered.[770] The companies also expressed a preference for the use of Y factors instead of Z factors because of the greater uncertainty associated with approval of Z factors.[771]

626. Several parties suggested that the exogenous adjustment criteria approved in Decision 2009-035 could also be used to evaluate the deferral accounts proposed as Y factors under PBR.[772] While parties acknowledged the suitability of utilizing a set of criteria for evaluating Y factors, there was some discrepancy regarding how to apply the criteria. Some companies argued that Y factors should be approved if some, but not necessarily all, of the Y factor criteria were met. The criterion suggested by some of the companies as not needing to apply in all circumstances is the "outside-of-management-control" criterion.[773] Some interveners disagreed with the companies, and argued that items that are within management's control should not be eligible for Y factor treatment.[774]

763 Exhibit 391.02, NERA second report, Section IV-E-7, paragraph 113, page 51.
764 Exhibit 636.01, CCA argument, Section 10.1, paragraph 159, page 64.
765 Exhibit 634.02, UCA argument, Section 10.1, paragraph 231, page 41.
766 Exhibit 300.02, UCA evidence of Russ Bell, A20, page 23.
767 Exhibit 642.01, IPCAA reply argument, Section 10.0, paragraph 13, page 2.
768 Exhibit 629.01, Calgary argument, Section 10.1, page 46.
769 Exhibit 476.01, ATCO Electric rebuttal evidence, paragraph 35, page 11; Exhibit 472.02, ATCO Gas rebuttal evidence, paragraphs 28-29, page 8; Exhibit 473.02, EPCOR rebuttal evidence, A19, page 25; Exhibit 477.01, AltaGas rebuttal evidence, Section 7, paragraph 82, page 29; Exhibit 633.01, Fortis argument, Section 1.0, paragraph 36, page 9.
770 Exhibit 369.01, AUC-IPCAA-4.
771 Exhibit 633.01, Fortis argument, Section 10.5, paragraph 207, page 96; Exhibit 631.01, ATCO Electric argument, Section 10.4, paragraph 244, page 61; Exhibit 632.01, ATCO Gas argument, Section 10.5, paragraph 271, page 84; Transcript, Mr. Mantei, Volume 9, page 1550; Transcript, Mr. Gerke, Volume 11, page 1792.
772 Exhibit 219.02, AUC-ALLUTILITIES-FAI-11; Exhibit 233.01, AUC-ALLUTILITIES-EDTI-11(a); Exhibit 248.02, AUC-ALLUTILITIES-AUI-11(a); The CCA suggests similar criteria in Exhibit 636.01, CCA argument, Section 10.2.1, paragraph 163, page 67.
773 Exhibit 211.01, NERA-AE-17; Exhibit 204.02, AUC-ALLUTILITIES-AG-11; Exhibit 248.02, AUC-ALLUTILITIES-AUI-10.
774 Exhibit 629.01, Calgary argument, Section 10.2, page 47; Exhibit 634.02, UCA argument, Section 10.1, paragraph 230, page 41.

Commission findings

627. There was no dispute among the parties that certain third party costs similar to those approved in Decision 2009-035 should qualify to be flowed through to customers. As well, most parties supported the flow through of costs similar to the Commission's administration fee.

628. The Commission agrees that the criteria approved in Decision 2009-035 should apply be to Y factor costs in this decision. The Commission agrees with parties that the types of third party flow-through costs approved in Decision 2009-035 should also be approved on a flow-through basis in this proceeding.

629. For Y factor costs that are not third party flow-through costs, some parties suggested that the deferral account criteria set out by the EUB in Decision 2003-100[775] be used as the criteria for approval.[776] In Decision 2003-100 the EUB stated:[777]

> The Board does not consider there to be a definitive Board policy regarding the use of deferral accounts. Rather, the Board's practice has been to evaluate the use of a deferral account on a case-by-case basis, on its own merit. The Board notes that ATCO Pipelines and the interveners suggested several criteria for the Board to consider in this situation including:
>
> - Materiality of the forecast amount,
> - Uncertainty regarding the accuracy and ability to forecast the amount,
> - Whether or not the factors affecting the forecast are beyond the utility's control,
> - Whether or not the utility is typically at risk with respect to the forecast amount.
>
> The Board notes that the criteria were suggested to address differing views with respect to risk, rate fluctuations, intergenerational inequity, and the Board's historical approach to deferral accounts. The Board considers that the suggested criteria are reasonable…

630. The criteria in Decision 2003-100 are similar to the exogenous adjustment criteria approved by the Commission in Decision 2009-035.[778] In both decisions the lists included criteria related to materiality and the events being beyond management's control. There was recognition from several parties that the exogenous adjustment criteria from Decision 2009-035 could be used to evaluate the deferral accounts proposed as Y factors under PBR.[779]

631. The ability to recover costs outside of the I-X mechanism should be an extraordinary remedy for cost recovery. If however, the company has no ability to influence the amount of certain costs and those costs are material in nature and not otherwise recoverable under the I-X mechanism, incentives are unaffected. Accordingly, the Commission adopts and clarifies the criteria established in Decision 2009-035 for the identification of eligible Y factor costs as follows:

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775 Decision 2003-100: ATCO Pipelines, 2003/2004 General Rate Application – Phase I, Application No. 1292783, December 2, 2003.

776 Exhibit 632.01, ATCO Gas argument, Section 10.2, paragraph 226, page 73; Exhibit 300.02, UCA evidence of Russ Bell, A20, page 22.

777 Decision 2003-100, Section 7.2.1, pages 115-116.

778 Decision 2009-035, Section 9.3, paragraph 247, page 54.

779 Exhibit 219.02, AUC-ALLUTILITIES-FAI-11; Exhibit 233.01, AUC-ALLUTILITIES-EDTI-11(a); Exhibit 248.02, AUC-ALLUTILITIES-AUI-11(a). The CCA suggests similar criteria in Exhibit 636.01, CCA argument, Section 10.2.1, paragraph 163, page 67.

1) The costs must be attributable to events outside management's control.
2) The costs must be material. They must have a significant influence on the operation of the company otherwise the costs should be expensed or recognized as income, in the normal course of business.
3) The costs should not have a significant influence on the inflation factor in the PBR formulas.
4) The costs must be prudently incurred.
5) All costs must be of a recurring nature, and there must be the potential for a high level of variability in the annual financial impacts.

632. The Commission considers that all criteria must ordinarily be satisfied before a cost will be considered for Y factor treatment. In addition to those Y factors that meet the above criteria, the Commission will allow companies to recover as Y factor rate adjustments specific costs incurred at the direction of the Commission and flow-through costs that are similar in nature to the flow-through items approved for ENMAX in Decision 2009-035. The Commission considers that having fewer Y factor accounts will make the PBR plans easier to administer. Y factors will only be approved in circumstances where there is a demonstrable need for them.

633. The Commission acknowledges the arguments made by some parties that denying certain Y factor accounts could impact the risk profiles of the companies. The Commission addresses consideration of the potential for risk impacts of PBR in Section 7.4.2.6.1 of this decision.

7.4.1 Materiality of Y factors

634. The UCA recommended the disallowance of several Y factor accounts on the basis that the amounts associated with the accounts are not material. The UCA suggested that "only if a proposed deferral account is to account for the potential of an error in forecasting that could produce a gain or loss of substantial magnitude, should the Commission then use the other criteria to determine if deferral treatment is warranted."[780]

635. While most parties acknowledged that assessing the materiality of Y factors is appropriate, EPCOR disagreed stating that:

> EDTI's proposed Y factor does not include a materiality threshold limit. Such a threshold limit is not required as the deferral accounts and reserve accounts included in EDTI's Y factor are related to costs that are material. These deferral and reserve accounts have already been approved by the Commission using materiality as one of the criteria for approval. Generic proceedings do not require a materiality threshold as, if the subject matter of the proceeding were not material, the Commission would not hold a generic proceeding in relation to it.[781]

Commission findings

636. Due to the high degree of similarity in the purpose and assessment of Y factors and Z factors, unless otherwise determined by the Commission, the Commission considers that the materiality threshold established in Section 7.2.1 for Z factors should also apply to Y factors.

[780] Exhibit 300.02, UCA evidence, A20, page 23.
[781] Exhibit 237.01, CCA-EDTI-5.

7.4.2 Specific proposed Y factors

637. The companies proposed a variety of different Y factor accounts in this proceeding, some of which existed, as flow-through accounts and deferral accounts, prior to the implementation of PBR and others which are new. Interveners raised many concerns over the proposed Y factor accounts. In general, the objections raised by interveners were raised on the basis that the proposed accounts did not meet certain eligibility criteria.

638. The UCA provided many recommendations with respect to specific Y factor accounts in its evidence. Specifically the UCA recommended the denial of the following Y factors accounts proposed by the companies:[782]

- Variable Pay Program
- Expansion of Defined Benefit Pension plan
- Changes in Weather Deferral Account
- Changes in Load Balancing Deferral Account
- Production Abandonment Costs
- Distribution to Transmission Contributions
- Vegetation Management
- Head Office Cost Allocation Percentages
- AUC Rule 026 Deferrals-IFRS
- Exchange Rate Deferral
- Design, Development and implementation of a Demand Side Management (DSM) Program.
- ATCO Centre Calgary Lease.

639. Calgary only commented on ATCO Gas' accounts, and had a more general approach of only recommending the continued use of two deferral accounts with the belief that all other accounts are not appropriate to be used under PBR. Calgary recommended that only transmission costs and income tax deductible capital costs should be allowed.[783]

640. IPCAA recommended "that only those deferral accounts considered in the recent GCOC proceeding should be approved in this proceeding, in order to maintain consistency between the Commission's findings in the GCOC decision and the risk profile of the utilities."[784] In addition, in reply argument, IPCAA stated that it generally supported the UCA's arguments concerning all matters related to Y factor accounts (such as deferral accounts, reserves and flow-through items).[785]

641. The CCA provided a number of specific recommendations in its argument,[786] however several companies objected to the inclusion of the recommendations in argument on the grounds that the recommendations could not be properly tested due to the lateness of their introduction to the proceeding.[787] The Commission will only give weight to the CCA recommendations it

[782] Exhibit 634.02, UCA argument, Section 10.1, paragraph 228, page 41.
[783] Exhibit 629.01, Calgary argument, Section 10.1, page 46.
[784] Exhibit 369.01, AUC-IPCAA-4.
[785] Exhibit 642.01, IPCAA reply argument, Section 10.0, paragraph 13, page 2.
[786] Exhibit 636.01, CCA argument, Section 10, pages 64-110.
[787] Exhibit 644.01, Fortis reply argument, Section 1.0, paragraph 19, page 3; Exhibit 648.02, ATCO Gas reply argument, Section 10.2, paragraph 327, page 93; Exhibit 647.01, ATCO Electric reply argument, Section 1, paragraph 31, page 10.

determines are based on the prior record of the proceeding, and will not consider new proposals or supporting evidence that were introduced for the first time in argument.

Commission findings

642. The Commission has reviewed the various Y factor accounts requested by the companies, and has grouped the accounts into seven different categories:

(1) Accounts that should be approved for flow-through treatment on the basis that they are similar to the flow-through items approved for ENMAX based on the Commission's findings in Section 7.4 above.

(2) Accounts that are a result of Commission directions, and therefore are eligible for flow-through treatment even though they may not satisfy certain criteria for Y factors.

(3) Accounts that meet the Y factor criteria, and therefore are eligible for flow-through treatment.

(4) Events where the impacts are unforeseen, and therefore are better to be assessed as Z factors.

(5) Accounts that are not eligible for Y factor treatment because they do not satisfy the outside-of-management-control criterion.

(6) Accounts that are not eligible for Y factor treatment because they do not satisfy the inflation criterion.

(7) Accounts that involve capital expenditures and are therefore better to be assessed as capital trackers.

643. The Commission considers that in many cases companies have asked for Y factors that are common amongst them. Because these accounts can be grouped together, the Commission will assess groupings of similar Y factor accounts for several companies in the sections that follow.

644. Some of the companies withdrew their requests for certain Y factor accounts during the course of the proceeding.[788] Accounts that the companies have removed have not been included in the assessments in the following sections because it is assumed that the accounts will not be utilized during PBR.

[788] Exhibit 389.01, ATCO Gas application updates, Section 2.4, paragraph 16, page 8 (withdrew deferral account for production abandonment costs and short term deferral accounts for IFRS implementation, NGTL/AP integration, Calgary head office lease); Exhibit 529.01, AltaGas corrections and amendments to application, Section 4, page 4 (withdrew deferral accounts for demand side management and natural gas system settlement code); Exhibit 633.01, Fortis argument, Section 10.2, paragraph 193, page 89 (withdrew exchange rate deferral account).

7.4.2.1 Accounts that are similar in nature to flow-through items approved for ENMAX

7.4.2.1.1 AESO flow-through items

645. All electric distribution companies accessing the electric transmission system in the province are charged by the AESO[789] for transmission services provided in relation to customers in their distribution service area. Accordingly, the distribution tariff of the electric distribution companies in this proceeding includes two components:[790]

- the distribution component, designed to recover the costs of owning and operating the distribution system; and
- the transmission component, designed to recover the AESO tariff charges to the distribution company.

646. ATCO Electric, Fortis and EPCOR indicated that while the rates covering the distribution component will be determined by the I-X mechanism, the AESO transmission access charges should be treated as flow-through items. The companies pointed out that the AESO charges have been subject to deferral account treatment under cost of service rate regulation and they proposed to continue using the existing deferral account mechanisms (with one modification, as further discussed below) to recover these costs under PBR. Historically, the companies used slightly different names for deferral accounts for the AESO charges, but the purposes for the costs are essentially the same:

Table 7-2 AESO flow-through items for electric distribution utilities

ENMAX[791]	ATCO Electric	EPCOR	Fortis
AESO load settlement costs	AESO load settlement costs[792]	AESO load settlement deferral account[793]	AESO load settlement cost reserve[794]
SAS rates in the distribution tariff	System access service payments[795]	System access service rates[796]	AESO system access service[797]
TAC deferral account		Transmission charge deferral account[798]	AESO charges deferral account[799]
Balancing Pool allocation refund rider	Balancing Pool adjustment[800]	Balancing Pool rider	Balancing Pool adjustment rider[801]

789 The AESO is a not-for-profit organization that plans and operates the transmission system in Alberta. http://www.aeso.ca/index.html.
790 Exhibit 633, Fortis argument, page 142.
791 Decision 2009-035, Section 9.3, paragraph 251, page 55.
792 Exhibit 98.02, ATCO Electric application, Section 6, paragraphs 119-122, page 6-10.
793 Exhibit 103.02, EPCOR application, Section 2.3.5, Table 2.3.5-1, page 51.
794 Exhibit 100.02, Fortis application, Section 6.1.1, page 26.
795 Exhibit 98.02, ATCO Electric application, Section 6, paragraphs 92-103, pages 6-2 to 6-6.
796 Exhibit 103.02, EPCOR application, Section 3.3, paragraphs 254-255, pages 81-82.
797 Exhibit 100.02, Fortis application, Section 13.1, paragraph 160, page 45.
798 Exhibit 103.02, EPCOR application, Section 3.3, paragraphs 254-255, pages 81-82.
799 Exhibit 100.02, Fortis application, Section 13.1, paragraphs 163-165, pages 46-47.
800 Exhibit 98.02, ATCO Electric application, Section 14, paragraph 265-266, page 14-2.
801 Exhibit 100.02, Fortis application, Section 13.1, paragraphs 166-168, page 47.

Commission findings

647. In Decision 2009-035, the Commission agreed with ENMAX that the company has no control over the AESO charges and approved flow-through treatment of these costs for the purposes of ENMAX's FBR plan.[802] All of the electric distribution companies are subject to the same types of costs and therefore the Commission considers that these costs satisfy the Y factor criteria enumerated above. The Commission also considers that achieving consistency with the flow-through items approved in the ENMAX FBR plan is fair and reasonable. Accordingly, the Commission finds that the AESO related cost items, as presented in Table 7-2 above, will be treated as flow-through items for the purposes of the PBR plans of Fortis, EPCOR and ATCO Electric.

648. To the extent that the companies have existing rider mechanisms to pass through these costs to customers, for billing consistency those existing mechanisms will continue under PBR.

7.4.2.1.2 Inclusion of volume variance in the transmission access charge deferral accounts

649. In their PBR proposals, the electric distribution companies proposed one modification to their existing transmission access charge deferral accounts. Currently, these deferral accounts reconcile only forecast to actual variances related to the AESO price changes. The companies bear the risk of forecast to actual variances related to transmission volumes (as measured by certain billing determinants such as metered energy, customer load, peak demand, etc.). In other words, if the AESO were to change its rates, the companies would be kept whole across its forecast volumes through a deferral account. However, the companies accept the risk of the actual volumes being lower or higher than forecast.[803] This arrangement can be generally represented as:

> ***Transmission Access Deferral =***
> ***Forecast volume × (Actual AESO prices - Forecast AESO prices)***

650. The companies indicated that they do not have any meaningful control over transmission volumes as they are completely driven by customer load requirements that can vary from year to year and month to month.[804] IPCAA agreed that the companies have "little if any control over customer loads."[805] IPCAA also observed that the only practical option to control transmission volumes can create risks that customer loads will be interrupted:

> Since utilities have and should have no direct control over customer load, their only practical option is to shift load between summer and winter peaking PODs [points of delivery] to minimize AESO tariff demand ratchets. Since distribution is largely radial in nature [Exhibit 306.01 page 2], this is rarely possible; urban utilities, with their denser service areas, are the only entities with meaningful substation switching options. However such switching creates significant risks that customer loads will be interrupted.[806]

651. Furthermore, the companies indicated that transmission volumes have become increasingly difficult to forecast due to a more complex AESO tariff structure. ATCO Electric

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802 Decision 2009-035, paragraph 251.
803 Exhibit 98.02, ATCO Electric application, Section 6, paragraphs 95-97.
804 Exhibit 98.02, ATCO Electric application, Section 6, paragraph 98; Exhibit 633, Fortis argument, page 142.
805 Exhibit 635, IPCAA argument, paragraph 99.
806 Exhibit 635, IPCAA argument, paragraph 102.

noted that the structure of the AESO's tariff has changed over the years shifting from energy related costs to demand-related costs which are more difficult to forecast.[807] In particular, ATCO Electric observed that the change in demand-related costs has increased from 42 per cent of the total AESO costs in 2004 to 78 per cent of the total system access service (SAS) costs.[808] Fortis shared these concerns.[809]

652. ATCO Electric and Fortis also expressed their view that the complexity of forecasting the transmission volumes will be more pronounced under PBR, since the companies will be forecasting billing determinants over longer periods of time (i.e., over the PBR term).[810] In that regard, Fortis submitted that in the absence of volume true-up, the company would need to update its transmission volumes forecast annually to effectively attempt to manage this transmission risk. In Fortis' view, this annual update was not consistent with "regulatory streamlining envisioned for PBR."[811]

653. Fortis also observed that one of the reasons the Commission relied upon for imposing volume risk on Fortis in Decision 2012-108[812] was that it might provide an additional incentive for the company to more accurately forecast its distribution billing determinants. In that regard, Fortis submitted that this determination was made in the context of a cost of service regime and would be less applicable to PBR. In Fortis' view, under PBR, forecasting of transmission volumes will be less critical in terms of sharing any risks between customers and the company.[813] ATCO Electric also agreed that the "circumstances associated with forecasting risk under PBR are significantly different than under cost of service regulation."[814]

654. Based on these considerations, EPCOR, ATCO Electric and Fortis proposed that their transmission access charge deferral accounts include both price and volume variances under PBR.[815] In other words, the companies requested that the AESO charges be treated as a full dollar-for-dollar flow-through item in their PBR plans. Under this arrangement, the actual transmission costs incurred will equal the actual transmission revenues received. This arrangement can be generally represented as:

> ***Transmission Access Deferral =***
> ***(Actual volume - Forecast volume) × (Actual AESO prices - Forecast AESO prices)***

655. The CCA noted that in two recent decisions, Decision 2011-375[816] and Decision 2012-108, the Commission determined that volume variances should not be included in the transmission cost deferral accounts in a cost of service rate design regime. In the CCA's

807 Transcript, Volume 4, pages 728-729.
808 Exhibit 631, ATCO Electric argument, paragraph 336.
809 Transcript, Volume 12, page 2243, lines 5-23.
810 Exhibit 98.02, ATCO Electric application, Section 6, paragraph 99; Exhibit 633, Fortis argument, pages 143-144.
811 Exhibit 633.01, Fortis argument, pages 143-144.
812 Decision 2012-108: FortisAlberta Inc. Application for Approval of a Negotiated Settlement Agreement in respect of 2012 Phase I Distribution Tariff Application, Application No. 1607159, Proceeding ID No. 1147, April 18, 2012.
813 Transcript, Volume 12, page 2242, lines 5-16 and page 2244, lines 7-14.
814 Exhibit 639, ATCO Electric reply argument, paragraph 369.
815 Transcript, Volume 10, page 1874, lines 19-21 (EPCOR); Exhibit 633, Fortis argument, pages 143-144; Exhibit 631, ATCO Electric argument, paragraph 337.
816 Decision 2011-375: EPCOR Distribution & Transmission Inc. 2010-2011 Phase II Distribution Tariff Application, Application No. 1606833, Proceeding ID No. 980, September 15, 2011.

view, the Commission's determinations "apply as much in a cost of service environment as they do in the PBR regime."[817] Accordingly, the CCA argued that the companies' transmission access charge deferral accounts should continue to include price variance only.[818]

656. The UCA noted that in Decision 2012-108, the Commission indicated that it will "consider the merits of volume reconciliation for distribution utilities under the PBR regime in due course, following the issuance of a decision on Proceeding ID No. 566."[819] As such, the UCA recommended that the Commission continue with a generic proceeding for examining the issue of volume true-up as referenced in Decision 2012-108.[820]

657. IPCAA also noted the Commission's determination in Decision 2012-108 referenced by the UCA and recommended that the implementation of comprehensive PBR be delayed until incentives are developed that will encourage the distribution companies "to prudently minimize the transmission and distribution facilities installed in their service area."[821]

Commission findings

658. As observed by the UCA and IPCAA, in Decision 2012-108 the Commission reaffirmed its intention to consider the issues related to volume reconciliation under the PBR framework on a consistent basis for all distribution companies following the issuance of a decision in this proceeding.[822] However, having considered the evidence filed by the parties, the Commission agrees with Fortis' and ATCO Electric's view that a determination on volume reconciliation under PBR can be made in this proceeding.[823]

659. The Commission agrees with ATCO Electric's and Fortis' explanation that transmission volumes are driven by customer load requirements. Furthermore, as stated in a number of recent decisions, the Commission agrees with the electric distribution companies' assessment that they have no meaningful control over transmission volumes due to the specifics of the current structure of the AESO system access rates (more heavily oriented to demand-related charges versus energy-related charges) and the companies' limited ability to undertake seasonal switching of loads between points of delivery.[824] IPCAA came to the same conclusion.[825]

660. Nevertheless, analysing EPCOR's and Fortis' cost of service rate applications, the Commission concluded that these companies were able to forecast transmission volumes with reasonable accuracy, as demonstrated by relatively small volume variances in their respective deferral accounts.[826] However, in that case the companies were updating their billing determinants forecasts every two years, in their rate applications. The Commission agrees with ATCO Electric's and Fortis' arguments that the same level of precision will not likely be attainable if the companies will be forecasting their billing determinants for the duration of the

[817] Exhibit 636, CCA argument, paragraph 402.
[818] Exhibit 636, CCA argument, paragraphs 404-405.
[819] Decision 2012-108, paragraph 127.
[820] Exhibit 634.02, UCA argument, paragraph 433.
[821] Exhibit 635, IPCAA argument, paragraph 104 and Exhibit 642, IPCAA reply argument, paragraph 608.
[822] Decision 2012-108, paragraph 127.
[823] Exhibit 644, Fortis reply argument, paragraphs 182-183; Exhibit 639, ATCO Electric reply argument, paragraph 368.
[824] Decision 2011-375, paragraph 188 and Decision 2012-108, paragraph 115.
[825] Exhibit 635, IPCAA argument, paragraphs 99 and 102.
[826] Decision 2011-375, paragraph 189 and Decision 2012-108, paragraph 117.

PBR term. Therefore, the Commission will require the companies to file forecast billing determinants for the following year as part of their annual PBR rate adjustment filings.

661. More importantly, the Commission explained in recent decisions dealing with EPCOR's and Fortis' rate applications, that under a cost of service regulatory framework, the distribution revenue requirement established in Phase I applications is divided by the forecast billing determinants for the test period to design customer rates. In other words, the accuracy of customer rates and the companies' ability to recover their approved revenue requirement is highly dependent on the accuracy of their billing determinants forecasts.

662. Furthermore, under the current regulatory framework, the electric distribution companies accept the risk related to the difference between the forecast and actual billing determinants when recovering their approved distribution revenue requirement. In these circumstances, the Commission determined that under a cost of service rate making framework, the absence of volume true-up on transmission charges would provide a stronger financial incentive to the companies to accurately forecast their billing determinants to ensure reasonable recovery of both the distribution tariff revenue and transmission access charges. Overall, taking into account the impact of forecast billing determinants on customer rates and the companies' revenues, the Commission considers that under cost of service rate making, regulatory efficiencies stemming from a more rigorous billing determinants forecast outweigh the potential disadvantages of the companies bearing risk on transmission volumes.[827]

663. In contrast, under PBR, the companies' costs will not be driving their revenues. As set out in Section 4 of this decision, under the price cap plans approved for ATCO Electric, EPCOR and Fortis, customer rates for each year will be established by way of the I-X mechanism, regardless of a company's actual costs and the amount of energy transported through a company's system. In these circumstances, forecasting of billing determinants will have a minimal impact on customer rates.[828] As Fortis observed:

> And we would note that under PBR that all falls away. Under PBR we essentially have rates for the distribution component of costs increasing I minus X. We have billing determinant volumes growing on an actual basis, and the product of those two things are really the revenues that FortisAlberta will receive for its distribution service.[829]

664. Accordingly, the Commission agrees with Fortis' view that under PBR, there is no purpose for maintaining the true-up of transmission flow-through accounts of electric distribution companies limited to price-only.

665. IPCAA expressed concerns that the current deferral account mechanism creates "unnecessary cost uncertainty, delay, and administrative costs."[830] In that regard, as outlined in Bulletin 2012-04,[831] the Commission had initiated a review of the electric distribution companies'

[827] Decision 2011-375, paragraph 191 and Decision 2012-108, paragraphs 120-121.
[828] As set out in Section 4, under a price cap plan, billing determinants will be used nonetheless to apportion to customers other components of the PBR formula, outside of the (I-X) mechanism such as flow-through items, capital trackers, Z factors, etc.
[829] Transcript, Volume 12, page 2242, lines 5-16.
[830] Exhibit 635, IPCAA argument, paragraph 103.
[831] Bulletin 2012-04, Commission-initiated electric transmission quarterly rider process review, Proceeding ID No. 1678, March 29, 2012.

transmission quarterly rider mechanisms.[832] As part of that review, ATCO Electric, ENMAX, EPCOR and Fortis filed their applications to standardize their respective transmission access charge rider mechanisms. In the Commission's view, these applications address, among other things, the types of issues identified by IPCAA in this proceeding. For example, the companies are proposing to move to a prospective approach to setting their quarterly riders. Under this method, the transmission component of the companies' rates in any quarter will be reflective of the AESO charges in that particular quarter. As such, it will no longer be the case that transmission charges will be based on a calculation "whose results are unknowable until the utility releases them months after the fact."[833] Furthermore, the companies are proposing to standardize and simplify their quarterly riders, so that these applications can be reviewed with minimal scrutiny, reducing time delay and the administrative cost of dealing with these riders.[834] The Commission intends to address IPCAA's concerns in Proceeding ID No. 1678.

666. In light of the above considerations, the Commission approves the inclusion of volume variance in the transmission flow-through accounts of the electric distribution companies for the purposes of their PBR plans. The Commission expects that with this modification, the AESO related cost items will be dollar-for-dollar flow-through items in the companies' PBR plans. At the time of their annual transmission deferral reconciliation, the companies must ensure that the actual transmission revenues received equal the actual transmission costs incurred. As noted in the previous section of this decision, subject to this modification, the Commission directs Fortis, EPCOR and ATCO Electric to use their existing deferral mechanisms to flow through the transmission access costs to customers under PBR.

667. As indicated in Decision 2012-108, the Commission is committed to considering the issues related to volume reconciliation under the PBR regime on a consistent basis for all electric distribution companies.[835] The Commission considers that the same reasoning for including volume variances in ATCO Electric's, EPCOR's and Fortis' transmission charge deferral accounts under PBR applies to ENMAX as well. As such, the Commission directs ENMAX to bring this matter forward to the Commission as part of the next application dealing with the company's transmission access charge deferral account.

7.4.2.1.3 Transmission flow-through for gas utilities

668. The Commission considers that certain flow-through items requested by the gas companies serve a similar purpose, and have similar mechanisms to the AESO flow-through items approved for the electric distribution utilities. The transmission costs deferral account requested by ATCO Gas[836] falls into this category. ATCO Gas simply flows through the transmission rates charged by the transmission service provider to customers. ATCO Gas has requested volume variances to be included in this account under PBR for reasons that are similar to the electric distribution companies' requests to include volume variances in the transmission flow-through accounts. The Commission approves flow-through treatment using the existing rider mechanism for the transmission costs deferral account, and also approves the inclusion of volume variances in the account. AltaGas has also proposed to continue to address its gas procurement function and costs related to transportation by third parties separately from the

832 Proceeding ID No. 1678.
833 Exhibit 635, IPCAA argument, paragraph 103.
834 Proceeding ID No. 1678, Exhibit23.02, Exhibit 24.01, Exhibit 25.01 and Exhibit 26.02.
835 Decision 2012-108, paragraph 127.
836 Exhibit 99.01, ATCO Gas application, Section 2.5.1.2.4, pages 24-25.

I-X mechanism through its existing gas costs recovery rate and third party transportation rate mechanisms.[837] The Commission approves AltaGas' treatment.

7.4.2.1.4 Farm transmission costs

669. Fortis intends to continue its existing practice of flowing through farm transmission costs to the AESO based on a prescribed formula.[838] Other flow-through items associated with AESO transactions have been approved as part of this decision, and it is therefore suitable for these costs to receive flow-through treatment.

7.4.2.2 Accounts that are a result of Commission directions

670. All of the companies included Y factor accounts or indicated the requirement for future Z factors related to future decisions issued by the Commission. The UCA acknowledged the need for a utility to have the opportunity to recover the costs related to changes in regulation.[839] As discussed in Section 7.4, an exemption to certain Y factor criteria will be permitted for certain cost items that have been incurred by a company in compliance with a direction of the Commission.

7.4.2.2.1 AUC assessment fees

671. In Decision 2010-146, the Commission approved flow-through treatment of AUC assessment fees for ENMAX under its FBR plan.[840] AUC assessment fees are common to all of the companies, and all of them asked for deferral or flow-through treatment of these fees.[841] Some of the companies did not request a specific flow-through account for these costs, as they had grouped these costs together with their hearing costs deferral account. The Commission will continue with flow-through treatment of AUC assessment fees. For those companies that included these fees in another deferral account with other types of costs, these companies are directed to separately identify the AUC assessment fees component in their Y factor calculations.

7.4.2.2.2 Effects of regulatory decisions

672. Several companies requested Y factors to flow through the impacts of regulatory decisions.[842] The Commission finds that regulatory efficiency would be achieved if the companies are able to treat the financial impact of items the Commission has already determined to be necessary as Y factor adjustments. The Commission therefore finds that the financial effects to companies that are clearly identified in a Commission direction may, with approval of the Commission, be included as Y factor adjustments in the annual PBR rate adjustment filings process. Specific changes related to generic cost of capital proceedings are discussed in Section 7.4.2.6.1 below.

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837 Exhibit 110.01, AltaGas application, Section 1.1, paragraph 9, page 3.

838 Exhibit 100.02, Fortis application, Section 6.3, paragraphs 106-108, page 30.

839 Exhibit, 300.02, UCA evidence of Russ Bell, A21, page 33.

840 Decision 2010-146, Section 9.1.1, paragraph 100, page 16.

841 Exhibit 98.02, ATCO Electric application, Section 6, paragraph 152, page 6-16; Exhibit 100.02, Fortis application, Section 6.1.3, paragraph 95, page 27; Exhibit 103.02, EPCOR application, Section 2.3.5, Table 2.3.5-1, page 51; Exhibit 110.01, AltaGas application, Section 7.1.1, paragraph 81, page 23; ATCO Gas includes AUC administration costs in hearing costs according to Transcript, Volume 6, pages 918-919.

842 Exhibit 98.02, ATCO Electric application, Section 6, paragraphs 200-203, page 6-28; Exhibit 99.01, ATCO Gas application, Section 2.5.2.6, paragraph 108-109, page 38; Exhibit 100.02, Fortis application, Section 6.4.4, paragraphs 114-115, page 32; Exhibit 103.02, EPCOR application, Section 2.3.5, Table 2.3.5-2, page 51.

7.4.2.2.3 Hearing costs

673. All of the companies requested Y factor treatment for hearing costs presently collected through their hearing cost deferral accounts.[843] The Commission considers that intervener costs approved to be paid pursuant to AUC cost decisions are a result of directions from the Commission, and therefore are eligible for collection through a Y factor adjustment. The Commission considers that management has a reasonable level of control over its internal hearing costs, and therefore the company portion of hearing costs will be subject to the I-X mechanism.

674. The company portion of the hearing costs that will be subject to the I-X mechanism will be the average awarded company hearing costs for the years 2009, 2010 and 2011. This amount will be included in going-in rates for the purpose of determining the rates for 2013 replacing the amounts presently included in the revenue requirement for 2012 for the hearing cost deferral account. Intervener costs will be treated as a flow-through Y factor account to be reconciled in the annual PBR rate adjustment filings.

7.4.2.2.4 AUC tariff billing and load settlement initiatives

675. EPCOR included a Y factor for AUC tariff billing and load settlement initiatives.[844] The Commission considers that because these costs are a result of Commission directions they will be approved as a flow-through Y factor account to be reconciled in the annual PBR rate adjustment filings.

7.4.2.2.5 UCA assessment fees

676. The gas companies are required to make payments for UCA assessment fees. These are similar in nature to the AUC assessment fees and accordingly the Commission considers flow-through treatment to be warranted. The Commission understands that ATCO Gas included UCA fees as part of its hearing costs[845] and that AltaGas has requested a PBR deferral account that includes both AUC and UCA assessments.[846] To the extent that ATCO Gas and AltaGas included these fees in another deferral account with other types of costs, these companies are directed to separately identify the UCA assessment fees component in their Y factor calculations.

7.4.2.3 Accounts that meet the Y factor criteria and are eligible for flow-through treatment

677. The Commission has examined the following proposed Y factor accounts and finds that they satisfy the Y factor criteria established in Section 7.4 and therefore are eligible for flow-through treatment.

7.4.2.3.1 Municipal fees

678. Several companies indicated that they intend to continue with either a deferral account or flow-through treatment for franchise fees and property taxes. Fortis requested that its municipal

843 Exhibit 98.02, ATCO Electric application, Section 6, paragraphs 152-155, page 6-16 to 6-17; Exhibit 99.01, ATCO Gas application, Section 2.5.1.2.1, paragraph 58, page 23; Exhibit 100.02, Fortis application, Section 6.1.3, paragraphs 95-96, pages 27-28; Exhibit 103.02, EPCOR application, Section 2.3.5, Table 2.3.5-1, page 51; Exhibit 110.01, AltaGas application, Section 7.1.1, paragraph 81, page 23.

844 Exhibit 103.02, EPCOR application, Section 2.3.5, Table 2.3.5-1, page 51.

845 Exhibit 99.01, ATCO Gas application, Section 2.5.1.2.1, paragraph 58, page 23.

846 Exhibit 110.01, AltaGas application, Section 7.1.1, paragraph 81, page 23.

franchise fee riders and its Rider A-1 municipal assessment riders continued.[847] Continuation of existing rider mechanisms to collect municipal fees was also proposed by ATCO Electric[848] and ATCO Gas.[849] In addition, EPCOR requested a property, business and linear tax deferral account.[850] Because these costs satisfy the Y factor criteria they will be treated as a flow-through item. Where there is an existing rider mechanism the companies are directed to use that mechanism and, in the absence of an existing rider mechanism, the companies will dispose of balances in a deferral account as part of the annual PBR rate adjustment filings process.

7.4.2.3.2 Load balancing

679. ATCO Gas requested continuation of its load balancing deferral account (LBDA). The UCA recommended the continued use of the load balancing deferral account, but recommended that ATCO Gas' suggestion to true-up the account every year instead of waiting until the account exceeds specified threshold levels should be denied.[851] Because the account meets the Y factor criteria, the Commission determines that ATCO Gas may continue to use its load balancing deferral account in its current form. The Commission considers that the continued use of a threshold approach, as proposed by the UCA, is necessary to minimize the regulatory burden of reviewing applications. Therefore, during the PBR term, the existing process for dealing with the load balancing deferral account will continue as described by ATCO Gas where "the recovery or refund of the LBDA balance is triggered if either of the North or South accounts exceeds $5 million (receivable or payable) for six consecutive months, or if either account exceeds $10 million in any one month."[852] ATCO Gas is directed to use a separate rider outside of the PBR formula to settle balances with customers.

7.4.2.3.3 Weather deferral

680. ATCO Gas requested continuation of its weather deferral account (WDA). The reduction to the risk that ATCO Gas faces with respect to weather was recognized in a previous GCOC proceeding in the form of a 100 basis points reduction to the equity thickness of ATCO Gas.[853] The weather deferral account not only protects ATCO Gas in years when its earnings would otherwise be negatively impacted by warmer than normal weather, but it also protects customers in years when colder than normal weather would require them to pay higher utility bills. The UCA recommended the continued use of the weather deferral account, but recommended that ATCO Gas' suggestion to true up the account every year instead of waiting until the account exceeds specified threshold levels should be denied.[854] Because the adjustment to risk has already been reflected in going-in rates, because the account meets the Y factor criteria, and because the account can have benefits for both the company and customers, ATCO Gas may continue to use its weather deferral account in its current form without annual true-ups. ATCO Gas described the current process as follows: "a WDA rate rider application is triggered to recover or refund the balance if and when either the North or South accounts is at or greater than $7 million

847 Exhibit 100.02, Fortis application, Section 13.1, paragraph 149, page 41.
848 Exhibit 207.01, AUC-BOTHATCO-AE-6.
849 Exhibit 206.02, AUC-BOTHATCO-AG-6.
850 Exhibit 103.02, EPCOR application, Section 2.3.5, Table 2.3.5-1, page 51.
851 Exhibit 634.02, UCA argument, Section 10.1, paragraph 249, page 45.
852 Exhibit 99.01, ATCO Gas application, Section 2.5.1.2.7, paragraph 72, page 28.
853 Transcript, Ms. Wilson, Volume 7, page 1321.
854 Exhibit 634.02, UCA argument, Section 10.1, paragraph 249, page 45.

(receivable or payable) on April 30 of each year."[855] ATCO Gas is directed to use a separate rider outside of the PBR formula to settle balances with customers.

7.4.2.3.4 Production abandonment

681. ATCO Gas withdrew its request for this account in its application update subject to the results of the review and variance on Decision 2011-450.[856] The issue is currently under consideration in other proceedings, and the Commission considers that in the interim this deferral account will continue as a Y factor. Pending the results of other proceedings reviewing the recoverability of production abandonment costs, the Commission will reassess whether the continuation of this Y factor under PBR is necessary. In the interim, while the issues around this deferral account are being addressed in other proceedings, ATCO Gas is directed to continue to track the balance associated with this deferral account. The settlement of the balance will not occur until the other proceedings have determined the proper treatment.

7.4.2.3.5 Income tax impacts other than tax rate changes

682. Several companies requested various income tax Y factor accounts. These accounts include:

- The income tax deductible capital cost deferral account and the deduction of deferrals for income taxes requested by ATCO Electric.[857]
- The income tax deductible capital costs requested by ATCO Gas.[858]
- The CRA re-assessment deferral and the income tax payable flow-through requested by Fortis.[859]
- The income tax timing differences flow-through account requested by AltaGas.[860]

683. The Commission will address the portion of the Y factor account relating to income tax rate changes in Section 7.4.2.6.2. All of the remaining income tax Y factor accounts relate to the treatment of temporary tax differences or the reassessment of prior income tax returns. The Commission understands that these types of adjustments only affect the earnings of regulated entities due to the use of the flow-through income tax method, and that most companies in other industries normalize their income tax expenses to reflect the impact of changes to future income tax liabilities and assets.

684. Calgary proposed that ATCO Gas should continue with deferral treatment for income tax deductible capital costs on the basis "that utility management cannot manage the level of expenditure for these items despite bona fide, competent and good faith efforts."[861] The UCA suggested that the continuation of income tax deferral accounts is appropriate, and noted that in

[855] Exhibit 99.01, ATCO Gas application, Section 2.5.1.2.6, paragraph 69, pages 27-28.
[856] Exhibit 389.01, ATCO Gas application updates, Section 2.4, paragraph 16, page 8.
[857] Exhibit 98.02, ATCO Electric application, Section 6, paragraphs 123-145, pages 6-10 to 6-15, and paragraph 147, page 6-15.
[858] Exhibit 99.01, ATCO Gas application, Section 2.5.1.2.8, paragraph 75, page 29.
[859] Exhibit 100.02, Fortis application, Section 6.1.5, paragraphs 99-100, page 28 and Section 6.4.3, paragraph 113, page 32.
[860] Exhibit 110.01, AltaGas application, Section 7.1.2, paragraph 82, page 24.
[861] Exhibit 629.01, Calgary argument, Section 10.2, page 48.

Decision 2009-214,[862] the Commission expressed its intention to initiate a proceeding which will address consistent income tax methodologies for all utilities.[863]

685. As noted by the UCA, the Commission, in Decision 2009-214, indicated that it intends to initiate a proceeding which will address consistent income tax methodologies for all utilities. The Commission confirms its intention to initiate a generic income tax proceeding following the release of this decision. In the interim, the Commission considers that material changes in income tax expenses that result from the treatment of temporary tax differences or the reassessment of prior income tax returns should be passed on to customers until such time as any change in income tax methodology may be directed by the Commission. Accordingly, the income tax Y factor accounts respecting the treatment of temporary tax differences or the reassessment of prior income tax returns requested by ATCO Gas, ATCO Electric, Fortis and AltaGas are approved. These changes will be addressed through Y factor adjustments as part of the annual PBR rate adjustment filings.

7.4.2.4 Accounts that are unforeseen events, and therefore should be assessed as Z factors instead

686. The discussion on specific items in this section is not intended to obligate the Commission to approve Z factor treatment in future proceedings for any of the items discussed. This section simply identifies the types of items that have been proposed as Y factors by the companies, but which should be tested as Z factors because of their unforeseen and infrequent nature. When Z factor applications are submitted the merits of each item will be tested in detail as to whether or not they actually qualify. The following accounts fall into this category.

7.4.2.4.1 Self-insurance/reserve for injuries and damages

687. Fortis,[864] EPCOR,[865] ATCO Electric[866] and ATCO Gas[867] all requested that their self-insurance deferral accounts be continued as Y factors. While there may be some activity in these accounts on an annual basis, the primary purpose of these accounts is to capture the effects of major events that are not covered by insurance. The Commission considers that during the PBR term the significant events that the companies are concerned about could be addressed as Z factors while the non-significant events should be covered by the I-X mechanism. The Commission will allow the companies to include a provision in their going-in rates calculated as follows. The provision will be equal to the average value of each event that was included in their deferral account or as an adjustment to their reserve account for the most recent five-year period. This amount is to be reflected in the companies going-in rates. The companies are directed to identify this adjustment to going-in rates in their compliance filings and the Commission will make a determination in the compliance filing decision as to whether or not the adjustment is reasonable.

[862] Decision 2009-214: ATCO Gas, 2008-2009 General Rate Application Phase I, Income Tax Module, Application No. 1553052, Proceeding ID. 11, November 12, 2009.
[863] Exhibit 300.02, UCA evidence of Russ Bell, A21, page 30.
[864] Exhibit 100.02, Fortis application, Section 6.1.4, paragraphs 97-98, page 28.
[865] Exhibit 103.02, EPCOR application, Section 2.3.5, Table 2.3.5-2, page 51.
[866] Exhibit 98.02, ATCO Electric application, Section 6, paragraphs 156-162, pages 6-17 to 6-18.
[867] Exhibit 99.01, ATCO Gas application, Section 2.5.1.2.2, paragraph 59, page 24.

7.4.2.4.2 Depreciation rate changes

688. Fortis,[868] ATCO Electric,[869] ATCO Gas[870] and AltaGas[871] all requested Y factors related to depreciation changes. The companies requesting these Y factors indicated that depreciation studies do not occur on an annual basis. However, even when new depreciation studies are performed, it is not certain that significant changes in depreciation rates will result. If a substantial change does occur, the change may be a result of changes in management assumptions, which would cause the change to not be eligible for flow-through treatment in the form of either a Y factor or Z factor. However, if the change results from some circumstance that is outside of management control, the change may be eligible for Z factor treatment. Due to the unforeseeable nature of depreciation changes, the infrequent occurrence, and the uncertainty as to whether the changes would be eligible for flow-through treatment, depreciation changes will not be treated as a Y factor.

7.4.2.4.3 International Financial Reporting Standards (IFRS)/accounting changes

689. Fortis[872] and AltaGas[873] requested Y factor treatment for accounting changes. The Commission considers that impacts associated with major changes to accounting standards, whether it is the initial adoption of IFRS or any other modifications to accounting standards, should be infrequent. Other than the initial adoption of IFRS, it is unforeseeable when subsequent major changes to accounting standards will occur. In addition, Fortis recognized that the majority of the AUC Rule 026[874] changes it would need to make are required for financial reporting purposes, and that regulatory reporting would likely not be affected.[875] As a result, the Commission determines that because of the infrequent and unforeseeable nature of accounting changes, they should be assessed as Z factors.

7.4.2.4.4 Acquisitions

690. ATCO Electric,[876] ATCO Gas[877] and AltaGas[878] all requested several different types of acquisitions to be treated as Y factors including: REA acquisitions, gas co-op acquisitions, and municipal annexations. The UCA objected to the flow-through treatment of these accounts on the basis that a company should only make an acquisition when it is economically beneficial for the company to do so, and therefore allowing flow-through treatment is not necessary.[879] The Commission considers that under certain circumstances it may not actually be left to the discretion of management as to whether or not the acquisition is made. In those circumstances, it may be necessary to assess the impact of an acquisition through a Z factor application. Acquisitions within the control of management would not generally qualify as either a Z factor or a Y factor.

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868 Exhibit 100.02, Fortis application, Section 6.4.1, paragraph 110, page 31

869 Exhibit 98.02, ATCO Electric application, Section 6, paragraphs 194-195, pages 6-26 to 6-27.

870 Exhibit 99.01, ATCO Gas application, Section 2.5.2.4, paragraph 104, page 37.

871 Exhibit 529.01, AltaGas corrections and amendments to application, Section 4, page 4.

872 Exhibit 100.02, Fortis application, Section 6.1.2, paragraph 92-94, pages 26-27.

873 Exhibit 110.01, AltaGas application, Section 7.1.2, paragraph 82, page 24.

874 Rule 026: *Rule Regarding Regulatory Account Procedures Pertaining to the Implementation of the Internal Financial Reporting Standards*, effective December 20, 20122 (Rule 026).

875 Transcript, Mr. Lorimer, Volume 11, page 2161.

876 Exhibit 98.02, ATCO Electric application, Section 6, paragraphs 191-191, page 6-26.

877 Exhibit 99.01, ATCO Gas application, Section 2.5.2.3, paragraph 103, page 37.

878 Exhibit 110.01, AltaGas application, Section 7.1.2, paragraph 82, page 24.

879 Exhibit 634.02, UCA argument, Section 10.1, paragraphs 277-282.

7.4.2.4.5 Defined benefit pension plan

691. In its 2010 Pension Common Matters application the ATCO utilities (ATCO Gas, ATCO Electric and ATCO Pipelines) applied for deferral account treatment for their pension expenses. In Decision 2010-189,[880] the Commission approved a deferral account for each ATCO utility to recover the special payments required to amortize an unfunded liability associated with the defined benefit portion of the Canadian Utilities Limited defined benefit pension plan.[881] In Decision 2010-553,[882] the Commission further explained that the purpose of the special payment deferral accounts is to capture the impact of timing differences that may arise between when special payment amounts are approved by the Alberta Superintendent of Pensions and consequently paid by the ATCO utilities and when amounts are approved by the Commission for inclusion in revenue requirement.[883] These differences were captured in a deferral account to keep both customers and shareholders whole.

692. ATCO Gas and ATCO Electric requested an expansion of their special payment deferral accounts by way of Y factor treatment associated with their defined benefit pensions plans.[884] AltaGas requested the creation of a pension deferral account with respect to their defined benefit pension plan costs.[885] These companies argued that when actuarial evaluations are made they can result in significant changes to the funding of the plan. Further, it is not simple to isolate changes resulting from special payment requirements resulting from an under funding of the plan from current service or other funding requirements.

693. The UCA recommended denial of the expansion of existing pension deferral accounts. The UCA referenced Decision 2010-189 where the Commission recognized the difference between special payments and current service pension costs, and the Commission determined that current service pension costs are no different than other compensation costs and therefore should not receive deferral treatment.[886]

694. The Commission agrees with the UCA that current service pension costs are no different from other compensation costs and accordingly denies the requested expansion of the ATCO Gas and ATCO Electric special payment deferral accounts and the creation of a pension deferral account for AltaGas.

695. With respect to the existing special payment deferral accounts of ATCO Gas and ATCO Electric distribution, the Commission considers that under a PBR environment there is no need to monitor the timing differences for which the deferral accounts were created. Accordingly, the existing special payment deferral accounts for ATCO Gas and ATCO Electric distribution will be discontinued upon implementation of PBR.

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880 Decision 2010-189: ATCO Utilities, Pension Common Matters, Application No. 1605254, Proceeding ID. 226, April 30, 2010.
881 Decision 2010-198, paragraph 94.
882 Decision 2010-553: ATCO Utilities, Compliance Filing Pursuant to Decision 2010-189, ATCO Utilities Pension Common Matters, Application No. 1606289, Proceeding ID. 693, December 1, 2010.
883 Decision 2010-553, Section 3.1, paragraph 17, page 4.
884 Exhibit 98.02, ATCO Electric application, Section 6, paragraphs 113-118, pages 6-8 to 6-10; Exhibit 99.01, ATCO Gas application, Section 2.5.1.2.5, paragraphs 65-68, pages 26-27.
885 Exhibit 529.01, AltaGas corrections and amendments to application, Section 4, page 4.
886 Exhibit 634.02, UCA argument, Section 10.1, paragraph 244, page 44.

696. In the event of a material change to a company's special payment obligations (either positively or negatively), a Z factor application would be available to address this change.

7.4.2.4.6 Insurance proceeds

697. ATCO Gas proposed a deferral account for insurance proceeds in compliance with AUC Rule 026.[887] The Commission considers that if an event involving insurance proceeds that would have a material impact on operating costs occurs, then ATCO Gas may apply for flow-through treatment as a Z factor.

7.4.2.5 Accounts that do not meet the outside-of-management-control criterion

7.4.2.5.1 Variable pay

698. ATCO Gas[888] and ATCO Electric[889] proposed the continued use of deferral accounts for variable pay and AltaGas proposed the continued use of its short term incentive plan deferral account as Y factors.[890] The UCA argued that variable pay is only one component of compensation and is subject to the same management control as all other components of compensation.[891] The Commission considers that companies should be left to develop employee compensation programs that will have the best impact on their performance, and therefore Y factor accounts related to variable pay are not approved. The Commission considers that such an approach complies with PBR Principle 1 that states that "a PBR plan should, to the greatest extent possible, create the same efficiency incentives as those experienced in a competitive market while maintaining service quality."[892]

7.4.2.5.2 Vegetation management

699. ATCO Electric requested Y factor treatment for vegetation management costs on the basis that the costs are outside of the control of management because there are a limited number of contractors that do the work, and that competition for services significantly increases the rates that the contractors charge.[893] The UCA indicated that "the creation of a Vegetation Management deferral account reduces the incentive to find creative and innovative ways to manage this function, and reduce costs."[894] The Commission does not accept ATCO Electric's argument. Vegetation management costs are entirely within the control of management.

7.4.2.5.3 Head office allocation changes

700. ATCO Gas[895] and ATCO Electric[896] requested Y factor treatment for changes to head office allocation percentages. The UCA expressed concern about the possibility of cost shifting under PBR between affiliates and the companies and proposed that significant changes in corporate structure and affiliate agreements should be reviewed by the Commission and, if approved, the effects of the change should be flowed through to customers.[897] Several of the

[887] Exhibit 389.01, ATCO Gas application updates, Section 2.4, paragraph 16, page 8.
[888] Exhibit 99.01, ATCO Gas application, Section 2.5.1.2.3, paragraph 60, page 24.
[889] Exhibit 98.02, ATCO Electric application, Section 6, paragraphs 148-151, page 6-16.
[890] Exhibit 529.01, AltaGas corrections and amendments to application, Section 4, page 4.
[891] Exhibit 634.02, UCA argument, Section 10.1, paragraph 243, page 44.
[892] Bulletin 2010-20, Rate Regulation Initiative, Section 3, page 2.
[893] Transcript, Mr. Freedman, Volume 4, page 755.
[894] Exhibit 634.02, UCA argument, Section 10.1, paragraph 261, page 48.
[895] Exhibit 98.02, ATCO Electric application, Section 6, paragraphs 171-176, pages 6-20 to 6-22.
[896] Exhibit 99.01, ATCO Gas application, Section 2.5.1.3.1, paragraphs 79-80, page 30.
[897] Exhibit 634.02, UCA argument, Sections 11.3 and 11.4, paragraphs 299-309, pages 55-56.

companies indicated that they would be willing to apply for Commission approval of material changes to affiliate agreements.[898]

701. The Commission finds that head office allocations are not outside of the control of the companies' management or that of their parent company and do not qualify as a Y factor.

702. EPCOR's witness, Dr. Weisman, indicated that the exclusion of earnings sharing mechanisms from a PBR plan should eliminate the need for strict monitoring of affiliate transactions because the incentive to shift costs to affiliates to avoid sharing earnings is eliminated.[899] The Commission agrees. As the Commission has not approved earnings sharing mechanisms in this decision, the need to isolate changes to affiliate agreements in a Y factor account has been substantially mitigated. However, the Commission has approved re-opener provisions and an efficiency carry-over mechanism that rely on the calculation of a return on equity. Therefore, the companies are directed to file all new material affiliate agreements, material changes to affiliate agreements and significant changes to corporate structure that have a substantial impact on the operating costs of the company.

7.4.2.5.4 AMR implementation

703. AltaGas requested Y factor treatment for the implementation of AMR (automated meter reading). AltaGas believes that if it were to implement AMR during the PBR term that the payoff for the investment would not be possible during a single PBR term. The UCA objected to the inclusion of an AMR deferral account indicating that "[t]he type of innovation covered by AMR is the same type of efficiency gains that is intended by PBR Principle 1, that a PBR should provide the same incentives as a competitive market."[900] The Commission agrees. AMR should be undertaken only if it will achieve efficiencies that will outweigh the costs. This decision is not outside of management control. Therefore there is no need for Y factor treatment.

7.4.2.6 Accounts that do not meet the inflation factor criterion

7.4.2.6.1 Changes in the cost of capital

704. Some of the companies asked for a Y factor adjustment to rates to account for changes to the Commission approved rate of return on equity.[901] Fortis,[902] ATCO Gas[903] and ATCO Electric[904] requested a Y factor adjustment to recover the impacts of changes in financing rates (i.e., cost of debt).

705. In its GCOC decisions, the Commission establishes an approved ROE for the companies under its jurisdiction. As well, it has been the Commission's practice to account for the differences in risk among the individual companies by adjusting their capital structures (i.e., the

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898 Transcript, Ms. Wilson, Volume 4, page 780; Exhibit 384.02, AUC-ALLUTILITIES-FAI-25(b); Exhibit 381.01, AUC-ALLUTILITIES-AUI-25(a).

899 Transcript, Dr. Weisman, Volume 9, page 1765.

900 Exhibit 634.02, UCA argument, page 35, paragraph 193.

901 Exhibit 98.02, ATCO Electric application, page 6-28, paragraph 202; Exhibit 99.01, ATCO Gas application, page 38, paragraph 109; Exhibit 100.02, Fortis application, page 32, paragraph 114; Exhibit 103.02, EPCOR application, page 51, table 2.3.5-2; Exhibit 110.01, AltaGas application, page 24, paragraph 82.

902 Exhibit 100.02, Fortis application, Section 6.4.2, paragraphs 111-112, pages 31-32.

903 Exhibit 99.01, ATCO Gas application, Section 2.5.2.5, paragraphs 105-107, pages 37-38.

904 Exhibit 98.02, ATCO Electric application, Section 6, paragraphs 196-199, page 6-27.

ratio of equity to debt).[905] Under cost of service regulation, the Commission approves a forecast of the company's cost of debt in its revenue requirement.

706. Both the I and the X in the PBR formula apply to the companies' distribution rates that are established through a cost of service proceeding. All of the distribution costs that are recovered through those rates, including the cost of debt and the cost of equity, are included in the going-in rates. In Section 5.2.1 of this decision the Commission determined that changes in the cost of capital (both debt and equity) are captured in the approved I factor. This means that the approved I factor in the I-X mechanism reflects changes in all of the companies' costs over time, including the cost of debt and equity. Therefore, the Commission finds that no specific changes to customer rates should be made to take into account changes in the Commission's approved generic ROE or changes in the cost of debt during the PBR term.

707. The Commission agrees with Dr. Lowry when he stated:

> But the one that raises an eyebrow to me in this category is the financing of – financing rate changes. I have never seen a plan involving an index that also involves an adjustment for financing rate changes. You would think that the – there is a danger of double-counting of that since [if] there is a change in interest rates eventually it will have an effect on general inflation rates. And this is particularly so inasmuch as the other – the second inflation measure proposed by ATCO Gas is the CPI for Alberta…[906]

708. It follows that including a separate flow-through component for changes in the ROE would also amount to double-counting.

709. The Commission recognizes that the conclusions it has reached with respect to the treatment of the cost of equity in the PBR framework are different than the approach taken by the Commission in the ENMAX FBR framework. The Commission has benefited from the evidence and testimony on this matter that was not available to it in the ENMAX FBR proceeding.

710. The Commission understands that a change to the risk profile of the companies may result from the transition to PBR. The Commission will consider this issue in the upcoming GCOC proceeding. If the Commission determines that there is a change to the risk profile of the companies as a result of the transition to PBR, the Commission will make a one-time adjustment to the companies' rates to reflect any adjustment to the companies' capital structure.

7.4.2.6.2 Income tax rates

711. ATCO Electric[907] proposed Y factor treatment to recover any changes to income tax rates. AltaGas' witness, Mr. Retnanandan, discussed why AltaGas would not try to recover the impact of tax rate changes from customers, stating "potentially on the PBR, the changes in tax rates would be covered under something like the inflation factor. So that would be duplicating, if you would, to recognize the income tax rate changes as part of the AUI Z factors."[908] The Commission considers that major changes to the calculation of income tax payments, such as a change in income tax rates, should impact the entire economy, and as such, should be captured

[905] See for example, Decision 2011-474: 2011 Generic Cost of Capital, Application No. 1606549, Proceeding ID No. 833, December 8, 2011, paragraph 169.
[906] Transcript, Volume 14, pages 2660, line 18 to page 2661, line 2.
[907] Exhibit 98.02, ATCO Electric application, Section 6, paragraph 146, page 6-15.
[908] Transcript, Mr. Retnanandan, Volume 9, page 1614.

by the I factor. To the extent that a change could occur that only impacts a select group of companies, and therefore not be captured by the I factor, it may be warranted to consider the change as a Z factor. However, due to the infrequent nature of such changes, it is not necessary to establish a Y factor account.

7.4.2.7 Requested capital project Y factors

712. Some items classified as Y factors by the companies relate to specific capital programs that may or may not proceed at some point during the PBR term that the companies considered to fall outside of the revenues that would be available to fund the project through the application of the I-X mechanism and customer growth. These proposed Y factors are listed in the following table.

Table 7-3 Capital-related flow-through items requested by utilities

AltaGas	ATCO Electric	ATCO Gas	EPCOR	Fortis
n/a	Material investments unique in nature	Material investments unique in nature	n/a	Externally driven capital expenditures
n/a	Distribution to transmission contributions	Transmission driven costs (capital component)	n/a	n/a
n/a	n/a	Urban mains replacement expenditures	n/a	n/a

713. The Commission considers that eligibility for these capital-related items should be assessed by way of a capital tracker application. See Section 7.3.2.4.

7.4.3 Collection mechanism for third party flow-through items

714. For flow-through items that have existing rider mechanisms in place, the companies generally suggested the continuation of the existing mechanisms. The changes to the rate riders associated with these mechanisms are separate from the rate adjustments resulting from the I-X mechanism. Due to the material nature of costs and the processes that are already in place for certain flow-through items, true-ups may be required more frequently than the annual PBR filings. One example is quarterly applications for SAS (system access service) riders. Some other flow-through items have traditionally been structured to have less than annual true-up mechanisms to avoid frequent true-up applications. Examples include the load balancing deferral account and weather deferral account for ATCO Gas. These deferral accounts have historically relied on a threshold triggering mechanism to determine when applications are submitted.

715. The companies proposed the continuation of several existing riders outside of the I-X mechanism:

- Fortis proposed to continue to use its transmission adjustment rider to flow through AESO charges, Rider A-1 Municipal Assessment Rider, Municipal Franchise Fee Riders, and the Balancing Pool Allocation Rider.[909]
- EPCOR proposed to continue to deal with its SAS rates and its transmission charge deferral account through separate applications.[910]

[909] Exhibit 100.02, Fortis application, Section 13.1, paragraphs 148-149, page 41.
[910] Exhibit 103.02, EPCOR application, Section 3.3, paragraph 255, page 82.

- ATCO Electric proposed continued use of its Rider S for its SAS deferral account.[911]
- ATCO Gas proposed to recover its transmission costs through its existing Rider T mechanism.[912]
- AltaGas proposed to continue to address its gas procurement function and costs related to transportation by third parties through its existing gas costs recovery rate and third party transportation rate mechanisms.[913]

Commission findings

716. The Commission considers that to the extent there are existing processes in place that are working well for addressing changes to the approved flow-through items, and those processes do not correspond to the timing of the annual PBR rate adjustment proceedings, these applications should continue to be dealt with as they are today.

7.4.4 Collection mechanism for other Y factor amounts

717. Unless otherwise directed, all Y factor costs incurred by a company other than the flow-through accounts that are collected through separate rate riders addressed in sections 7.4.2.1 and 7.4.2.3 above should be tracked and settled as a Y factor adjustment in its annual PBR rate adjustment filings.

718. The Y factor portion of the annual PBR rate adjustment filings will be comprised of two parts, the first being a provision for the Y factor amounts to be included in rates for the upcoming year, and the second being a true-up between the provision included in rates for the Y factor in the prior year and the actual amounts incurred in the prior year.

719. The provision for the first year of the PBR term which will be included in the compliance filing to this decision will generally be based on the amount that would have been approved for the 2012 test year of the GTA or GRA proceeding that forms the going-in rates (unless a different amount is specified elsewhere in this decision). Because these items will not be subject to the I-X indexing, the companies are directed to remove the amounts included in the 2012 revenue requirement from going-in rates in their compliance filing.

720. The Commission recognizes that addressing the impact of certain Commission directions impacting rates may be better suited to an adjustment to the rates that will be subject to the I-X mechanism rather than through a Y factor. The Commission will make the determination of how to incorporate the result of any directed rate adjustment at the time it makes the relevant decision.

721. The Commission also recognizes that some of the companies may have placeholders in place for certain expenses as part of the GTA or GRA proceedings that form the going-in rates for PBR. To the extent that other proceedings in front of the Commission will establish the approved expenses, and the companies will need to adjust their going-in revenue requirements, the Commission considers that the differences that exist between the placeholder amounts and the final approved amounts will be treated as Y factor adjustments or adjustments to rates that will be subject to the I-X mechanism, depending on the circumstances of the adjustment.

[911] Exhibit 98.02, ATCO Electric application, Section 6, paragraph 101, page 6-5.
[912] Exhibit 99.01, ATCO Gas application, Section 2.5.1.2.4, paragraph 64, page 25.
[913] Exhibit 110.01, AltaGas application, Section 1.1, paragraph 9, page 3.

7.4.5 Other existing deferral accounts, reserve accounts or flow-through mechanisms

722. Companies may not have identified all of the items they plan to flow through to customers in their PBR plans. For example ATCO Gas and ATCO Electric did not mention the continued use of existing riders to collect franchise fees and property taxes in their applications, but clarified that the existing treatment would continue in IR (information request) responses.[914] Similar omissions may have occurred for other PBR proposals because of assumptions made by the companies that the existing treatments will continue. Therefore, the Commission directs the companies to identify all of the riders that they intend to utilize during the PBR term that are outside of the I-X mechanism, describe the costs that are being collected on the riders, and explain why it is reasonable to continue to flow through the costs. Any items that have not been approved as a Y factor in this decision or are not identified as separate riders outside of the I-X mechanism by the companies in their compliance filings will be subject to the I-X mechanism.

8 Re-openers and off-ramps

723. A re-opener serves as a safeguard against unexpected results in the event that there is a problem with the design or operation of the plan that makes its continued operation untenable. All of the companies proposed that their PBR plans include a re-opener. As well, Calgary proposed a re-opener for ATCO Gas.[915]

724. An off-ramp is likewise intended to provide a safeguard against unexpected results in the operation of the PBR plan. Proponents of an off-ramp distinguished it from other forms of re-openers; arguing that once triggered, an off-ramp allows for the whole of the PBR plan to be examined and possibly terminated, whereas a re-opener is generally intended to provide an opportunity to investigate and modify a particular component in the operation or design of the PBR plan.[916] NERA stated that re-openers and off-ramps are common features of incentive plans and recommended their inclusion.[917]

725. As with the ENMAX FBR plan, EPCOR and AltaGas distinguished between unforeseen events that impact one or more elements of a PBR plan (to be considered by way of a re-opener) from events that jeopardize the PBR plan in its entirety (to be considered by way of an off-ramp) and accordingly both proposed separate re-opener and off-ramp. The UCA and the CCA simply urged the Commission to adopt the off-ramp that was approved for ENMAX in Decision 2009-035.

726. Fortis, ATCO Electric and ATCO Gas did not include specific off-ramp proposals in their respective PBR plans.[918] They instead proposed that provisions for a re-evaluation of their entire PBR plans be addressed as part of the process for re-opening and reviewing a PBR plan, if necessary. Fortis also noted that any "event material enough to merit consideration as to plan

914 Exhibit 207.01, AUC-BOTHATCO-AE-6; Exhibit 206.02, AUC-BOTHATCO-AG-6
915 Exhibit 298.02, Calgary evidence, page 29.
916 Exhibit 103.02, EPCOR application, page 77; Exhibit 634, UCA argument, page 58 (taken from Exhibit 228.01, page 55).
917 Exhibit 391.02, NERA second report, page 48, paragraph 104.
918 Exhibit 631.01, ATCO Electric argument, paragraph 265; Exhibit 632.01, ATCO Gas argument, paragraph 290; Exhibit 633.01, Fortis argument, paragraphs 228-229

change or potential termination could be brought forward under a Z factor application."[919] The UCA, the CCA and IPCAA all supported the inclusion of a re-opener. With respect to off-ramps, Calgary[920] agreed with the approach advanced by ATCO Gas.

Commission findings

727. A re-opener is commonly included in a PBR plan in order to address specific problems with the design or operation of a PBR plan that may arise or come to light as the term of the PBR plan unfolds, and which may have a material impact on either the company or its customers which cannot be addressed through other features of the plan. No party recommended proceeding with a PBR plan without including the facility for a re-opening and review of the plan if it is determined that there may be a problem with the plan. The Commission agrees that a facility to re-open and review the plan is a necessary element of any PBR plan.

728. However, the Commission agrees with Fortis, ATCO Electric and ATCO Gas that a specific facility for an off-ramp, as distinct from a re-opener, is not required in a PBR plan. All that is required, in the Commission's view, is an opportunity to re-open and review a PBR plan if a design or application flaw comes to light during the term of the PBR plan.

729. Accordingly, the Commission finds that any party, including the Commission on its own motion, will be permitted to bring an application to re-open and review a PBR plan, if there is sufficient evidence that there is a problem that cannot be resolved through another avenue available under the plan. In this regard, the Commission has approved in the PBR plans a number of mechanisms, including Z factors, K factors and various Y factors that allow for adjustments to rates outside of the adjustments required by the application of the I-X mechanism.

8.1 Specific proposals for re-openers

730. Parties to the proceeding proposed a number of events that should, in their view, lead to a re-opening and review of a PBR plan. The Commission has considered each of these events and made a determination as to whether each constitutes sufficient evidence that there is a problem with a PBR plan that can only be remedied by re-opening and review the plan.

731. Both the UCA and the CCA recommended that the Commission adopt a re-opener and proposed that the events leading to a re-opener as approved for ENMAX in Decision 2009-035 be adopted in this decision. In Decision 2009-035, the Commission accepted that the following events would generally require a re-opening of the ENMAX plan: if circumstances changed in a substantial or unforeseen manner; changes in regulatory status; changes to ENMAX's controlling ownership; or a misrepresentation by ENMAX.[921] With regard to specific events that would require a re-opening and review of the ENMAX plan, the Commission accepted the following: a failure to meet a specific performance standard for two consecutive years; material changes in accounting standards that have an annual impact greater than $5 million; expansion of ENMAX's service area where more than 10,000 customers are included within the expanded area; ROE results that are more than 300 basis points above or below the approved ROE for two

[919] Exhibit 633.01, Fortis argument, page 102.
[920] Exhibit 629.01, Calgary argument, page 54.
[921] Decision 2009-035, page 50

consecutive years; and an actual ROE result that is 500 basis points above or below the approved ROE for one year.[922]

732. Additionally, the CCA requested that, in the event that EPCOR's parent acquired additional businesses which had an impact on the amount of shared services allocated to EPCOR, a deferral account should be established and that it should not be included as a re-opener.[923] IPCAA specifically proposed that a re-opener should address any material degradation in customer service and urged the Commission to establish service quality standards in advance of any implementation of a PBR plan.

733. For ease of reference, the events that were proposed by each distribution company and by Calgary as evidence that a PBR plan should be re-opened and reviewed are set out in the table below:

Table 8-1 Summary of proposed re-opener mechanisms

	Fortis[924]	EPCOR[925]	ATCO Electric	AltaGas[926]	ATCO Gas	Calgary
ROE Re-opener	ROE before ESM is +/- 300 basis points above or below approved ROE.*	ROE is +/- 300 basis points* above/below approved ROE in two consecutive years. OR Actual ROE is +/- 500 basis points above/below approved ROE for one year.	If ESM, ROE before ESM is +/- 300 basis points above/below approved ROE. OR If no ESM, actual ROE is +/- 300 basis points above/below approved ROE.*[927]	Actual weather normalized ROE is +/- 300 basis points above/below approved ROE in two consecutive years. OR Actual ROE is +/- 400 basis points above approved ROE for one year.	If ESM, actual ROE after ESM is +/- 300 basis points above/below approved ROE. OR If no ESM, actual ROE is +/- 300 basis points above/below approved ROE. Actual ROE will be normalized. If no weather deferral account or if weather deferral account is a Z factor, then use actual ROE.[928]	Actual ROE is 300 basis points below approved ROE.
Default supplier Re-opener			Directed to resume role of default energy supplier.[929]	Material change in the default supply regulations.	Directed to resume role of default energy supplier.[930]	

922 Decision 2009-035, page 50.
923 Exhibit 636.01, CCA argument, at paragraphs 331-333.
924 Exhibit 100.02, Fortis application, page 35, paragraphs 126.
925 Exhibit 103.02, EPCOR application, page 79, paragraph 241.
926 Exhibit 110.01, AltaGas application, page 27, paragraph 87.
927 Exhibit 292.01, AUC-ALLUTILITIES-AE-16.
928 Exhibit 632.01, ATCO Gas argument, page 88, paragraph 285.
929 Exhibit 98.02, ATCO Electric application, page 10-1, paragraph 234.

	Fortis[924]	EPCOR[925]	ATCO Electric	AltaGas[926]	ATCO Gas	Calgary
Customer size/service area Re-opener		Expansion of service area of more than 10,000 additional customers in expansion area.	Loss of a franchise resulting in loss of 20,000 or more customers.[931]	Loss of 1000 service sites, excluding service site additions.	Loss of a franchise resulting in loss of 20,000 or more customers.[932]	
Accounting standard Re-opener		Material changes in accounting standards causing an annual impact on total revenue or expenses of >$2.5 million in aggregate in any one year.				
Service quality Re-opener		Failure to meet service quality performance target for two consecutive years.				
Cost of debt Re-opener				Spread between the embedded cost of debt and the I factor is ≥400 basis points.		
Z factor Re-opener				Cumulative, net, annual impact of Z factors on actual weather normalized ROE is ≥ ± 75 basis points in a single year.		
Management structure Re-opener				Material change in the management structure of AltaGas.		

* Approved ROE is the ROE approved by the Commission, generally in a generic cost of capital decision; most recently in Decision 2011-474.

930 Exhibit 99.01, ATCO Gas application, page 43, paragraph 124.
931 Exhibit 98.02, ATCO Electric application, page 10-1, paragraph 234.
932 Exhibit 99.01, ATCO Gas application, page 43, paragraph 124.

734. Additionally, and for ease of reference, the specific events that were proposed to initiate an off-ramp proposed by EPCOR, AltaGas, the UCA and the CCA are set out in the table below:

Table 8-2 Summary of proposed off-ramp mechanisms

Proposed off-ramp	EPCOR[933]	AltaGas	ENMAX off-ramps supported by CCA[934] / UCA[935]
Substantial change in circumstances	Substantial and unforeseen change in circumstance that renders continuation of PBR unjust or unreasonable. A substantial change in circumstance is defined as a change that increases distribution or transmission costs by $1 million or $0.50 million, respectively and these costs cannot be addressed as a Z factor.		Circumstances change in a substantial or unforeseen manner.
Regulatory status	Change in regulatory status if EPCOR no longer regulated by the Commission or a successor of the Commission.		Change in regulatory status.
Change in tax status	Change that results in a change in EPCOR'S taxable status.		
Change in control		Sale in controlling interest of AltaGas shares or disposition of all assets.[936]	Change in control.

Commission findings

735. In keeping with the Commission's finding that a specific facility for an off-ramp (as distinct from a re-opener) is not required in a PBR plan, the Commission will consider together the proposals made by parties for events that would result in either a re-opener or an off-ramp and determine whether each of these is sufficient to result in a re-opening and review of a PBR plan.

8.1.1 Return on equity

736. Common among the companies and the interveners were proposals to re-open and review a PBR plan if the actual ROE earned by a company exceeded the approved ROE by more than a pre-determined amount and, in some cases, fell below the approved ROE by a pre-determined amount.[937] It was generally argued that earning an actual ROE that is 300 basis points above or below the approved ROE is a sufficient indication that the PBR plan should be re-opened and reviewed. However, the parties differed as to whether the 300 basis point variance needed to be

933 Exhibit 103.02, EPCOR application, page 77.
934 Exhibit 636.01, CCA argument, page 115.
935 Exhibit 634.01, UCA argument, page 57, paragraph 320.
936 Exhibit 628.01, AltaGas argument, page 64.
937 Exhibit 98.02, ATCO Electric application, page 10-1, paragraph 233; Exhibit 99.01, ATCO Gas application, page 42, paragraph 123; Exhibit 100.02, Fortis application, page 36, paragraph 126; Exhibit 103.02, EPCOR application, page 79, paragraph 241; Exhibit 110.01, AltaGas application, page 27, paragraph 87; Exhibit 298.02, Calgary evidence, page 48, paragraph 169; Exhibit 634.02, UCA argument, page 58, paragraph 321; Exhibit 636.01, CCA argument, pages 112-113, paragraph 326.

recurring and whether the application of the measure should be symmetrically applied to both over and under-earning. EPCOR also proposed that a 500 basis point variance in one year should result in a re-opening of a PBR plan.[938]

Commission findings

737. The Commission finds that a material variance in the actual ROE achieved by a company when compared to the approved ROE may be an indicator that a PBR plan should be reviewed. The Commission expects that earnings may fluctuate from year to year and therefore finds that an earned ROE 300 basis points above or below the approved ROE in a single year is not sufficient evidence, on its own, that a PBR plan should be reviewed. However, the Commission does agree with the proposal of the CCA and EPCOR that an earned ROE that is 500 basis points above or below the approved ROE in a single year is sufficient to warrant consideration of a re-opening and review of a PBR plan. The Commission also agrees with the CCA, EPCOR and AltaGas that an earned ROE that is 300 basis points above or below the approved ROE for two consecutive years would constitute sufficient evidence to warrant consideration of a re-opening and review of a PBR plan. Both of the gas distribution companies have indicated that weather normalized ROE should be used in the assessment of re-openers. The Commission considers that the fluctuations in earnings caused by variations from normal weather typically experienced by the gas distribution companies would not be an indication that the operation of a PBR plan needs reconsideration. Therefore, the Commission accepts the use of a weather normalized ROE, as proposed by the gas distribution companies, to eliminate the possibility that variations in weather might trigger a re-opener.

738. The Commission has considered whether the rate of return on equity to be used for the purposes of determining if a company's earnings exceed the +/-300 or +/-500 basis point thresholds should be the ROE included in the going-in rates or the approved generic ROE for the year(s) in which the need for a re-opener is to be considered. Consistent with the Commission's determinations in Decision 2009-035[939] and Decision 2010-146,[940] dealing with the ROE used for the purpose of the ENMAX earning sharing mechanism, the Commission will utilize the Generic Cost of Capital ROE which may be determined from time to time by the Commission, as the ROE from which to calculate the +/-300 or +/-500 basis point re-opener thresholds.

739. The actual ROE of the companies to be used to determine whether a re-opener is warranted, will be the calculated in the same way as the ROE reported in the companies' annual AUC Rule 005 filings.

8.1.2 Change in service area

740. All of the companies, with the exception of Fortis, proposed that a material change to their service area or the number of customers to be served in their service area should result in a re-opening and review of their PBR plans. In this regard, EPCOR expressed concern with the potential for an unanticipated expansion in its service territory, while ATCO Electric, ATCO Gas and AltaGas were concerned with the potential for a material loss of customers.

741. Although a material change in service territory or number of customers may not signal that there is something wrong with the design or operation of a PBR plan, the Commission

[938] Exhibit 103.02, EPCOR application, page 79, paragraph 241.
[939] Decision 2009-035, paragraphs 418-419.
[940] Decision 2010-146, paragraphs 118-119.

agrees that such an event may warrant a re-opening and review of the affected company's PBR plan because the event may have a material impact on the company. The Commission considers that both a material contraction and expansion of customers or service territories may indicate that a re-opening and review of a PBR plan is required. With regard to the materiality thresholds proposed for the expansion or contraction of a company's service territory or customer base, the Commission considers that it is preferable to determine materiality on a case by case basis because materiality will vary from company to company and over time. However, in some cases a Z factor application may be sufficient, see Section 7.4.2.4.4.

8.1.3 Default supply obligations

742. ATCO Electric, ATCO Gas and AltaGas all identified, as events that would result in a re-opening and review of their respective plans, changes to the default supply regulation or a regulatory direction with respect to the assumption of default supply obligations in the case of ATCO Gas and ATCO Electric. The Commission has approved the creation of a Z factor in the PBR plans as more particularly set out in Section 7.2 of this decision. The Commission considers matters related to a change in law or a regulatory direction requiring a company to assume default supply obligations are best dealt with by way of an application for a Z factor adjustment, rather than as a re-opener. Nevertheless, if the event is such that it cannot be dealt with through a Z factor or other mechanism in the plan, an application for consideration of a re-opener could be filed.

8.1.4 Accounting standards

743. EPCOR proposed that material changes in accounting standards be included as an event that would signal the requirement for a re-opening and review of a PBR plan. Fortis[941] and AltaGas[942] identified material changes in accounting standards as a matter that should be addressed through a Y factor. The Commission agrees that material accounting changes may require an adjustment to rates under a PBR plan, but the impact of accounting changes should properly be considered in a Z factor application and do not necessarily signal that there is a problem with the design or operation of a PBR plan. Accordingly, the Commission finds that any rate adjustments required in response to material changes to accounting standards should be dealt with by way of a Z factor application.

8.1.5 Quality

744. IPPCA recommended that any material degradation in customer service should require a re-opening and review of a PBR plan. As well, EPCOR proposed that failure to meet service quality performance targets for two consecutive years should also require a re-opening and review of the company's PBR plan. These matters have been addressed in Section 14 of this decision in the Commission's findings regarding service quality.

8.1.6 Change of control

745. AltaGas proposed two events with respect to a change of ownership or control that would warrant a re-opening and review of its PBR plan leading, in its view, to an end to its PBR plan. These events are the sale of a controlling interest in AltaGas shares or the disposal of all or substantially all of its assets. The Commission considers that any change in controlling interest in AltaGas shares or the disposal of all or substantially all of the AltaGas assets is within the

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941 Exhibit 100.02, Fortis application, Section 6.1.2, paragraphs 92-94, pages 26-27.
942 Exhibit 110.01, AltaGas application, Section 7.1.2, paragraph 82, page 24.

control of the AltaGas shareholder, the companies' parent business entities or the management of AltaGas. That is, the owners or management of AltaGas have a choice with respect to transactions of this nature. The Commission does not consider that the PBR plan should be terminable as a result of a voluntary event of this nature. Further, it is expected that any new share or asset purchaser would, as part of its due diligence, be aware of the PBR plan and would take that into consideration as part of its purchase decision. There is no obvious correlation between a change in the ownership structure of a company or the sale of its assets, and a design or operational failure of a PBR plan. In any event, for rate setting purposes, the assets of a company must be transferred at net book value and the same assets would continue to be used to provide utility service both before and after the share or asset transfer. Accordingly, the proposal to end the PBR plan in the event of a change of ownership or control is denied

8.1.7 Change in regulatory status

746. EPCOR proposed that a change in regulatory status should result in a re-opening of the PBR plan, leading to an end to the plan. It is not clear to the Commission why a change in regulatory status would indicate a failure of the operation of the PBR plan. In any event, any issues arising from a change in regulator would, in the Commission's view, be a matter for the regulator of jurisdiction to consider.

8.1.8 Change in taxable status

747. EPCOR also proposed that a change in the taxable status of the company should result in a re-opening of the company's PBR plan with a view to ending the plan. It is also unclear to the Commission why such a change in the taxable status of the company would require the abandonment of the entire PBR plan. In the Commission's view, a change in taxable status would be a matter for consideration pursuant to a Z factor application.

8.1.9 Spread between debt costs and the I factor

748. AltaGas proposed that a material change in the spread between the cost of debt and the I factor should warrant a re-opening of its PBR plan. The Commission understands that, generally, any material changes in the spread between the cost of debt and the I factor should be occasioned by changes in interest rates in the economy and would therefore be eventually reflected in the indexes that make up the I factor, as discussed in Section 7.4.2.6.1. Otherwise, any company-specific changes to debt costs that are not a result of changes to interest rates in the economy as a whole are the result of actions taken by management and should not be the subject of a re-opener. Accordingly, the Commission does not agree with AltaGas that a material change in the spread between the cost of debt and the I factor should be an event that occasions a re-opening of the PBR plan.

8.1.10 Cumulative impact of Z factors

749. AltaGas also proposed that the cumulative impact of Z factors may warrant a re-opening of a PBR plan. The Commission considers that each Z factor application must be considered on its own merits and, if warranted, rates will be adjusted accordingly. The fact that there may be many Z factors approved for a company under its PBR plan is not, in and of itself, an indication that the PBR plan should automatically be re-opened and reviewed.

8.1.11 Organizational structure changes

750. AltaGas also proposed that changes to a company's organizational structure should result in a re-opening of a PBR plan. However, the Commission considers that changes to the organizational structure of the company are within the control of the company or its shareholder and would not, in the Commission's view, signal the need for the PBR plan to be re-opened and reviewed.

8.1.12 Material misrepresentation

751. The CCA and the UCA proposed that a PBR plan should be re-opened and reviewed with a view to ending the plan in the face of a deliberate material misrepresentation by management. The Commission has not been persuaded that this circumstance would signal a failure of the PBR plan that cannot be remedied. Accordingly, the Commission considers that a re-opening and review of the plan may be warranted in this circumstance, but the Commission cannot conclude that such an event would warrant ending the plan. In any event, the Commission considers that, if faced with such a misrepresentation, there are other remedies available to the Commission through the plan itself as well as the imposition of an administrative penalty pursuant to Section 63 of the *Alberta Utilities Commission Act*, SA 2007, c. A-37.2, which can be imposed to address such a serious matter.

8.1.13 Substantial change in circumstances

752. EPCOR proposed that a substantial change in circumstances should result in a re-opening and review of a PBR plan, leading in the company's view to an end to the plan. The Commission observes that a Z factor application is generally intended to consider a substantial change in circumstances. The Commission considers that, in the interests of regulatory efficiently and easing of the regulatory burden, the number of occasions for adjustments to rates by way of a Z factor or a re-opening and review of a PBR plan should be limited so as to allow the plans to generate the incentives that they are intended to create.

753. Nonetheless, the Commission recognizes that it is not possible to predict every circumstance that might legitimately be the subject of a re-opening and review of a PBR plan. Accordingly, should a substantial change in circumstances occur that does not, in the applicant's view, qualify for a Z factor application (as defined in Section 7.2 this decision) then an applicant may bring a re-opener application before the Commission for consideration. In this regard, the Commission is cognizant that, given a material event that is completely unforeseen and cannot be accommodated within the parameters of the PBR plan, it would be incumbent upon the Commission to re-open and review the plan.

8.2 Implementation

754. Several parties proposed that a re-opening of the PBR plan should be automatic following any of the events designated by the Commission as warranting a re-opening and review of a plan.

755. Calgary argued that "the design for re-openers contemplates a formulaic approach, once the utility is able to conclusively demonstrate that the achieved ROE is 300 basis points or more below the approved ROE, then the re-opener would be triggered automatically and parties would

begin discussions regarding potential changes to the existing PBR plan (either one-time or prospective or ongoing)."[943]

756. ATCO Electric and ATCO Gas stated that a re-opener should be automatic, once a triggering event is identified. Moreover, they suggested that, because the company is in the best position to be aware of an event that would signal the need for a re-opening of the PBR plan, it is the company that should notify the Commission that a re-opener of the PBR plan had been triggered.[944] Likewise, Fortis also proposed the automatic triggering of a re-opener if the upper or lower bounds of the earnings sharing mechanism it had proposed were exceeded.[945]

Commission findings

757. The Commission does not consider that a re-opening of the PBR plans should be automatic. As with any other matter before the Commission, any re-opening of a PBR plan must be on application to the Commission and the onus is on the applicant to demonstrate that a re-opening is warranted.

758. As noted above, the Commission finds that any party, including the Commission on its own motion, should be permitted to bring an application to re-open and review a PBR plan if there is sufficient evidence that there is a problem that cannot be resolved without re-opening and reviewing the plan. The Commission will consider applications to re-open and review a PBR plan and make a determination on the merits of the application as to whether a re-opening of the plan is warranted. In order to ensure fairness to all parties, parties are directed to notify the Commission of all events that they consider signal the need for a re-opener as soon as possible after they have been identified. The Commission also directs that the financial impact of any such event be captured in a separate account pending a ruling from the Commission. Any proposed financial impact is to be measured from the time the event occurred. The disposition of the balance in that account (positive or negative) would follow the Commission's ruling.[946]

9 Efficiency carry-over mechanism

9.1 Purpose and rationale for an efficiency carry-over mechanism

759. A company's incentive to find efficiencies weakens as the end of the PBR term approaches, because there is less time remaining for the company to benefit from any efficiency gains. The purpose of an efficiency carry-over mechanism (ECM) is to address this problem by permitting the company to continue to benefit from any efficiency gains after the end of the PBR term.

760. The CCA described an ECM as "a ratemaking mechanism designed to strengthen incentives for cost containment in the later years of a PBR period by permitting the utility to carry over some of the benefits of efficiency gains achieved in one PBR plan to the subsequent plan."[947] EPCOR, ATCO Gas and ATCO Electric proposed an ECM as part of their PBR plans.

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943 Exhibit 629.01, Calgary argument, page 53.
944 Exhibit 631.01, ATCO Electric argument, paragraph 262 and Exhibit 632.01, ATCO Gas argument, paragraph 286.
945 Exhibit 633.01, Fortis argument at paragraph 226 citing the evidence of Lorimer at Transcript, Volume 11, page 2173.
946 Decision 2009-035, ENMAX FBR contains a similar provision in paragraph 257.
947 Exhibit 636.01, CCA argument, paragraph 344.

To support the inclusion of an ECM, ATCO Electric and ATCO Gas explained that "…the incentive for identifying and implementing efficiency measures is strongest in the earlier years of the PBR Plan as the utility will then have several years in which to take advantage of the efficiency improvements."[948] EPCOR's witness Dr. Weisman explained that "[t]he regulated firm will have less than ideal incentives to innovate and discover efficiencies if it believes that the regulator will simply claw back these efficiency gains at the end of the PBR regime and pass them on to consumers in the form of lower rates. These adverse incentives are particularly pronounced toward the end of the PBR regime."[949] AltaGas stated it "recognizes the purpose of such a mechanism is to maintain incentives for investment in efficiency initiatives throughout the IR [incentive regulation] term, particularly where the benefits are not expected to be recovered during that term."[950]

9.1.1 ATCO Electric's capital efficiency carry-over mechanism

761. ATCO Electric proposed two forms of efficiency carry-over mechanisms, one based on rate of return and one for capital. ATCO Electric's K factor efficiency incentive mechanism (KFEI) was also initially requested by ATCO Gas,[951] but ATCO Gas subsequently withdrew its request for a KFEI mechanism in its updated filing.[952]

762. ATCO Electric's KFEI is calculated as any positive difference between the forecast cost of a capital project qualifying for a K factor (discussed in Section 7.3.3.2) and the actual cost of the capital project at the end of the term. Under its proposal, ATCO Electric would carry forward one-half of this positive difference into the first year following the end of the PBR term and one-third of the difference into the second year following the end of the PBR term.[953] The proposed KFEI is intended to ensure that the company has an incentive to look for efficiencies in its K factor capital programs over the course of the entire PBR term.[954]

763. The UCA did not support ATCO Electric's request for a KFEI "[a]s the UCA is not supporting the inclusion of any Capital adjustments outside specific Capital Trackers."[955]

Commission findings

764. The Commission considers that the KFEI proposed by ATCO Electric does not promote additional efficiency. The Commission finds that the structure of ATCO Electric's KFEI would provide an incentive for the company to over forecast its capital programs. When its actual costs are subsequently less than the over-forecast amount, the company would benefit, but not necessarily as a result of efficiency gains. For this reason, ATCO Electric's KFEI is denied.

9.1.2 Return on equity (ROE) efficiency carry-over mechanisms

765. EPCOR, ATCO Gas and ATCO Electric proposed ECMs based on ROE as part of their PBR plans. EPCOR explained that its ECM would be balanced. This means that it would carry

948 Exhibit 98.02, ATCO Electric application, page 11-1, paragraph 236, Exhibit 99.01, ATCO Gas application, page 43, paragraph 127.
949 Exhibit 103.03, written evidence of Dr. Weisman, paragraph 60.
950 Exhibit 628.01, AltaGas argument, page 74.
951 Exhibit 99.01, ATCO Gas application, Section 2.10.1, paragraph 128, page 44.
952 Exhibit 389.01, ATCO Gas updated filing, Section 2.8, paragraph 20, page 10.
953 Exhibit 98.02, ATCO Electric application, Section 11, paragraph 237, page 11-1.
954 Transcript, Volume 7, page 1280, Ms. Wilson.
955 Exhibit 634.01, UCA argument, paragraph 352.

over half of any earnings above its approved ROE for a period of two years following the end of the PBR term. It would also receive 100 per cent of any shortfall below the approved ROE for a period of two years following the end of the PBR term.[956] EPCOR also linked the size of its rate of return adjustment to its service quality measures, with lower service quality leading to a lower percentage adjustment.[957] EPCOR did not indicate whether there was a limit on the amount of the earnings or losses to be carried over.

766. In contrast to EPCOR's ROE ECM, the ATCO companies did not include an adjustment for earnings deficiencies in their ECM proposals and did not link their ECM to service quality measures. ATCO Electric and ATCO Gas described their proposed ROE ECM as follows:

> a post PBR add-on to the approved ROE equal to one half of the difference between the simple average ROE achieved over the term of the Plan and the simple average approved ROE over the term of the Plan (providing the difference is positive), multiplied by 50%, to a maximum of 0.5%. The "ROE bonus" would apply for 2 years after the end of the PBR Plan.[958]

767. Some parties noted that it does not appear that ECMs are common in North America. Very few examples of existing ECMs were cited or discussed in the hearing.[959] NERA indicated that ECMs are uncommon in PBR plans and stated that ECMs appear to be a desire to have the profit incentives of a PBR plan transcend to some degree beyond the end of the PBR term, "when rates would otherwise be squared with costs and profitable innovations capitalized for ratepayers."[960] Dr. Makholm suggested that in order to strengthen incentives, the term should be extended rather than including an ECM in a PBR plan.[961] NERA indicated that it has not seen evidence that adopting ECMs, as a partial lengthening of regulatory lag, "is worth the additional complications it would pose for the periodic future base rate cases."[962]

768. Some of the companies argued that ECMs provide a strengthening of incentives that outweigh any of the shortcomings of ECMs identified by NERA.[963] In addition, Dr. Lowry, the CCA and the ATCO companies submitted that an ECM is a deterrent to the gaming that might be associated with the timing of capital investments.[964]

769. Interveners, with the exception of Calgary, supported the general concept of ECMs, but they did not support the specific ECMs proposed by EPCOR and the ATCO companies.[965] The

[956] Exhibit 630.02, EPCOR argument paragraph 264.
[957] Exhibit 103.02, EPCOR application, paragraph 46 and Exhibit 630.02, EPCOR argument, paragraph 265.
[958] Exhibit 98.02, ATCO Electric application, page 11-2, paragraph 238 and Exhibit 99.01, ATCO Gas application, page 44, paragraph 129.
[959] Exhibit 391.02, NERA second report, paragraph 65. In its survey of PBR plans, NERA identified two that had an ECM. Exhibit 199.02, Cal-ATCO Gas I-32 identified one plan.
[960] Exhibit 391.02, NERA second report, page 9, paragraph 13.
[961] Transcript, Volume 1, Dr. Makholm's evidence, pages 194 and 195.
[962] Exhibit 391.02, NERA second report, paragraph 13.
[963] Exhibit 630.02, EPCOR argument, paragraph 270; Exhibit 631.01, ATCO Electric argument, paragraph 281; Exhibit 632.01, ATCO Gas argument, paragraph 303.
[964] Transcript, Volume 13, Dr. Lowry, page 2642; Exhibit 631.01, ATCO Electric argument, page 70; Exhibit 648.02, ATCO Gas argument, page 131, paragraph 480; Exhibit 636.01, CCA argument, paragraphs 342-347.
[965] Exhibit 634.01, UCA argument, paragraphs 356 to 359; Exhibit 642.01, IPCAA reply, paragraph 21. IPCAA states that it concurs with the UCA argument for ECMs and Exhibit 636.01, CCA argument, paragraph 342.

UCA argued that ATCO Gas and ATCO Electric have achieved ROEs prior to PBR that are in excess of approved levels. Therefore, the UCA recommended that the average of the actual ROE for the 2009 to 2012 period be used as the basis for the ECMs rather than the approved ROE for the PBR plan period because this level of ROE "represents the current level of efficiency."[966] The UCA stated, "[b]y basing the target on the actual achievement, the intent of the PBR to incent greater efficiency is maintained. If a lower target is used, the incentive to improve efficiency is lessened."[967]

770. While supporting the concept of an ECM based on actual ROE performance, the UCA also suggested that there must be recognition of any efficiency gains achieved prior to the commencement of PBR that are not reflected in the going-in rates. The UCA stated, "[s]ince there are identified efficiency gains coming out of the COS environment, there should be an ECM for both going-in-rates and for the end of term."[968] The UCA proposed addressing the going-in portion of its proposed ECM through an adjustment to going-in rates. If no efficiency gains are recognized in going-in rates, the UCA argued that there should be no ECM included in the PBR plans.[969]

771. The CCA stated that it supports a Commission directed "generic ECM module, preferably by negotiation, in the early part of the PBR term."[970] The CCA also stated that the record was insufficient to approve an alternative ECM.[971]

772. Calgary also rejected the inclusion of an ROE ECM in ATCO Gas' PBR plan, providing among its reasons that there is no evidence that lengthening the period for recovery guarantees incentives or results in improved efficiencies, that there is no guarantee that efficiencies are passed on to ratepayers and that an ECM only spreads the incentives over a longer period but does not strengthen the incentives.[972]

773. Dr. Weisman discussed that alternatively an open-ended term operates as an efficiency carry-over mechanism because rates are not reset.[973] AltaGas stated that "its proposal to include an option to extend the term of its IR [incentive regulation] Plan may be considered a form of ECM, as it potentially allows AUI to continue operating under the approved IR [incentive regulation] Plan for an additional two years."[974]

Commission findings

774. In Decision 2009-035, the Commission recognized "that the longer the term of an FBR plan, the stronger the incentives for utilities to improve their efficiency."[975] In recognition of this issue the Commission stated in its February 26, 2010 letter initiating the PBR initiative that:

> The Commission will initiate a proceeding during the first PBR term to consider how the success of the PBR plan should be judged and how it might be re-initiated, or rates re-

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[966] Exhibit 634.01. UCA argument, paragraph 359.
[967] Exhibit 634.01, UCA argument, paragraph 357.
[968] Exhibit 634.01, UCA argument, paragraph 346.
[969] Exhibit 634.01, UCA argument, paragraph 360.
[970] Exhibit 636.01, CCA argument, page 120 of 152, paragraph 343.
[971] Exhibit 636.01, CCA argument, page 120 of 152, paragraph 343.
[972] Exhibit 629.01, Calgary argument, pages 61 to 62.
[973] Transcript, Volume 10, Dr. Weisman, page 1827, lines 2 to 5.
[974] Exhibit 628.01, AltaGas argument, page 74.
[975] Decision 2009-035, paragraph 116.

based, at the end of the initial five-year term in a way that minimizes potential distortions to economic efficiency incentives

775. The Commission agrees that ECMs are an innovative mechanism that will allow for a strengthening of incentives in the later years of the PBR term and may discourage gaming regarding the timing of capital projects. The Commission finds that the incentive properties of an ECM encourage companies to continue to make cost saving investments near the end of the PBR term.[976] The Commission agrees with ATCO's proposal for an upper limit for earnings that can be carried over and finds the limit of 0.5 per cent to be reasonable. Accordingly, the Commission approves the ATCO companies' ROE ECM for inclusion in the ATCO companies' PBR plans. If any of the other companies wish to submit the same ECM in their PBR plans, they may do so in their compliance filings.

776. EPCOR's proposed ECM includes adjustments for both over- and under-earnings in the two years following the end of the PBR term. The UCA did not support EPCOR's ECM because it compensates for under-earning which would dampen incentives and shield the utility from the full impact of its decisions.[977] The Commission agrees. As discussed above, the Commission supports a 0.5 per cent limit to the amount of earnings which may be carried over. Accordingly, the Commission finds that EPCOR's ECM should not include an adjustment for under-earning and should limit the amount of earnings which can be carried over to a maximum of 0.5 per cent.

777. With respect to EPCOR's proposal to include service quality as part of its ECM, the Commission will be relying on AUC Rule 002 along with administrative penalties under Section 63 of the *Alberta Utilities Commission Act* to ensure that service quality is maintained. In Section 14, the Commission has determined that these measures are sufficient to address service quality. Accordingly, EPCOR's proposed service quality adjustments to its ECM formula are not required.

778. The Commission rejects the UCA's recommendation that the average of the actual ROE for the 2009 to 2012 period be used as the basis for the ECMs rather than the approved ROE for the PBR plan period. The Commission has already made its determinations on the 2012 going-in rates in Section 3 of this decision. The purpose of the ECM is to provide an incentive to the companies to continue to achieve efficiencies in the latter part of the PBR term. If the Commission were to adopt the UCA's proposal, this incentive would be distorted because it would require the assessment of the efficiencies gained during the PBR term against financial results from the past and under a different regulatory framework.

779. In the Commission's view, the correct ROE to use for the purposes of calculating the amount of the ECM is the average approved generic ROE in place for each year during the PBR term.

[976] Exhibit 636.01, CCA argument, paragraph 344; Transcript, Volume 13, pages 2647-2648; Exhibit 103.03, evidence of Dr. Weisman, paragraphs 59 and 60; Transcript Volume 10, page 1820; Exhibit 628.01, AltaGas argument, page 74; Exhibit 647.01, ATCO Electric reply argument, page 70, paragraph 281; Exhibit 648.02, ATCO Gas reply argument, page 95, paragraph 303; Exhibit 630.02, EPCOR argument, paragraph 270.

[977] Exhibit 634.01, UCA argument, paragraphs 358-359.

780. The actual ROE of the companies to be used for the purposes of calculating the amount of the ECM, will be the calculated in the same way as the ROE reported in the companies' annual AUC Rule 005 filings.

9.1.3 Authority to approve an ECM

781. In its argument, Calgary questioned whether ECMs comply with the statutory framework in Alberta and raised issues of jurisdiction. Calgary stated that the equitable allocation or sharing with customers of benefits from incentives to be approved by the Commission is a matter of jurisdiction. Calgary argued that the Commission does not have jurisdiction to approve ATCO Gas' ECM as it is not a sharing of benefits from incentives and it is contrary to law. Calgary referenced AUC PBR Principle 5,[978] Section 120(2)(d) of the *Electric Utilities Act* and Section 45(1)(a) of the *Gas Utilities Act*, RSA 2000, c. G-5, in support of the equitable sharing of benefits derived from utility incentives being required for ESMs (earnings sharing mechanism) and ECMs (efficiency carry-over mechanism).[979] Calgary also argued that ATCO Gas' ECM will operate outside of the five-year PBR plan term. Calgary stated:

> There is no rate base determined for such post PBR term as part of this Proceeding, and as a result, the Commission's approval of ATCO's ECM will be contrary to Section 37 (1) of the GUA, which requires the Commission to determine the rate base of the gas utility and fix a fair return on that rate base at the same time. Since the rate base to which the ECM would apply will be determined at the ti[m]e of rebasing, there is obviously a time disconnect between setting ROE elements today (in this Proceeding) and determining the rate base in the future to which the ECM would apply.[980]

782. Section 45(1) of the *Gas Utilities Act* states:

> 45(1) Instead of fixing or approving rates, tolls or charges, or schedules of them, under sections 36(a), 37, 40, 41, 42 and 44, the Commission, on its own initiative or on the application of a person having an interest, may by order in writing fix or approve just and reasonable rates, tolls or charges, or schedules of them,
>
> (a) that are intended to result in cost savings or other benefits to be allocated between the owner of the gas utility and its customers, or
>
> (b) that are otherwise in the public interest.

783. Section 120(2)(d) of the *Electric Utilities Act* reads:

> 120(2) A tariff may provide
> ….
> (d) for incentives for efficiencies that result in cost savings or other benefits that can be shared in an equitable manner between the owner of the electric utility and customers.

784. ATCO Gas responded to Calgary's questioning of whether ECMs comply with the statutory framework in Alberta. ATCO Gas stated that its ROE ECM is a sharing of benefits

[978] Bulletin 2010-20, page 3, Principle 5: "Customers and the regulated companies should share the benefits of a PBR plan."
[979] Exhibit 629.01, Calgary argument, pages 56 and 62.
[980] Exhibit 629.01, Calgary argument, page 62.

from incentives of 50 per cent of the difference between the average ROE and the approved ROE over the plan term, if the difference is positive.[981] Section 45(1)(a) of the *Gas Utilities Act* does not indicate when the intended cost savings or other benefits are to be allocated to customers. This section only addresses that cost savings or other benefits are intended to result in cost savings or other benefits to be allocated between the owner of a gas utility and its customers.[982] ATCO Gas pointed out that this is also the case for Section 120(2)(d) of the *Electric Utilities Act*[983] and both of these sections do not indicate that benefits have to be shared equally. Additionally, the Commission has been determining the fair rate of return for Alberta gas and electric utilities distinctly from determining rate base since Decision 2004-052,[984] which established a generic formula for the establishment of ROE. ATCO Gas argued that Section 37(1) has not been an issue since Decision 2004-052, and it will not be an issue under PBR.

785. With respect to the approval of its ROE ECM, ATCO Gas stated that the ROE ECM establishes the way in which a potential increase to a future ROE will be calculated. It does not establish the ROE for the utility. There is no inconsistency for the ROE ECM as the application of the effect of the ROE ECM will occur at the same time as the future ROE will be applied.[985]

Commission findings

786. Upon review of the legislation as well as the arguments of Calgary and ATCO Gas, the Commission finds that Section 45(1)(a) of the *Gas Utilities Act* and Section 120(2)(d) of the *Electric Utilities Act* allow for the approval of rates and tariffs that result in cost savings and other benefits to be allocated between utilities and their customers. Further, Section 5(h) of the *Electric Utilities Act* states that one of the purposes of the Act is "to provide for a framework so that the Alberta electric industry can, where necessary, be effectively regulated in a manner that minimizes the cost of regulation and provides incentives for efficiency." Section 102(2)(d) of the *Electric Utilities Act* specifically refers to incentives for efficiencies and allows the Commission to include incentives for efficiencies that result in cost savings or other benefits, which is consistent with PBR. In addition, Section 121(3) of the *Electric Utilities Act* provides that "[a] tariff that provides incentives for efficiency is not unjust or unreasonable simply because it provides those incentives."

787. By Order of the Lieutenant Governor in Council, the Commission has the authority under Section 45(1) of the *Gas Utilities Act* "to proceed to fix or approve just and reasonable rates, tolls or charges, or schedules of them, that may be charged by ATCO Gas and Pipelines Ltd. or AltaGas Utilities Inc. under section 45 of the Gas Utilities Act."[986]

788. ATCO Gas has correctly indicated that its ROE ECM would result in a sharing of any differences between its average ROE over the plan term and approved ROE, in the case where the average ROE over the term is higher than the approved ROE. Any benefits of a higher ROE

981 Exhibit 648.02, ATCO Gas reply argument, page 131 of 152, paragraph 482.

982 Exhibit 648.02, ATCO Gas reply argument, page 123 of 152, paragraph 455.

983 Exhibit 648.02, ATCO Gas reply argument, page 124 of 152, paragraph 456.

984 Decision 2004-052: Generic Cost of Capital, AltaGas Utilities Inc., AltaLink Management Ltd., ATCO Electric Ltd. (Distribution), ATCO Electric Ltd. (Transmission), ATCO Gas, ATCO Pipelines, ENMAX Power Corporation (Distribution), EPCOR Distribution Inc., EPCOR Transmission Inc., FortisAlberta (formerly Aquila Networks), Nova Gas Transmission Ltd., Application No. 1271597, July 2, 2004.

985 Exhibit 648.02, ATCO Gas reply argument, page 132 of 152, paragraph 483.

986 O.C. 235/2011 June 1, 2011.

would be shared with customers under ATCO Gas' ECM proposal. Further, the entire rationale for an ECM is to incent the company to pursue additional cost savings particularly through capital investment that it might not be otherwise inclined to do in the latter part of the PBR term. Customers will directly benefit from these additional cost savings when utility costs and revenues are next reviewed and rates are adjusted.

789. The Commission has considered the ECMs proposed by the companies in light of the legislative requirements under the *Electric Utilities Act* and the *Gas Utilities Act*. The ECMs as approved above provide for incentives for efficiencies, or are intended to result in cost savings or other benefits to be allocated between the owner of the utility and its customers.

790. Calgary argued Section 37(1) of the *Gas Utilities Act* requires that rate base and rate of return be approved at the same time. Section 37(1) stated that the Commission shall determine a rate base and "upon determining a rate base it shall fix a fair return on the rate base." Section 45(1) of the *Gas Utilities Act* states that instead of fixing or approving rates, tolls or charges, or schedules of them, under sections 36(a), 37, 40, 41, 42 and 44 of the Act, the Commission may approve rates that are intended to result in cost savings or other benefits to be allocated between the owner of the gas utility and its customers. This includes the jurisdiction to approve the provisions of an incentive plan that are intended to create incentives during the PBR term to achieve cost savings or other benefits to be allocated between the owner of the gas utility and its customers in a period beyond the initial plan term.

791. The Commission concludes that ECMs are consistent with the governing legislation and it is within the Commission's jurisdiction to consider ECMs as part of the PBR plan under Section 45(1) of the *Gas Utilities Act* and under sections 5(h), 120(2)(d) and 121(3) of the *Electric Utilities Act*.

10 Earnings sharing mechanism

792. An ESM (earnings sharing mechanism) is intended to address the potential that a regulated company will earn a return significantly above or below the approved ROE (return on equity) during the PBR term. An ESM generally establishes a formula for sharing with the company's customers earnings in excess of a designated amount and may provide for a sharing of any shortfall below a designated amount. The implementation of an ESM generally requires annual filings of ROE results and sharing calculations and some form of verification of these filings. An ESM is a common feature of first generation PBR plans.

793. The Commission approved an ESM in Decision 2009-035 as part of ENMAX's FBR plan. ENMAX's approved ESM provides for an annual sharing mechanism equal to 50 per cent of ENMAX's earnings that are over 100 basis points above the approved ROE established by the Commission. Sharing of these earnings is given effect by way of a reduction in rates in the year following the year in which the excess earnings were realized. The ENMAX ESM provides for a sharing of earnings above the approved ROE but not for a sharing of any earning below the approved ROE.

794. In approving the ESM for ENMAX, the Commission acknowledged that an ESM blunts efficiency incentives but recognized that performance-based regulation was a relatively new

development in Alberta utility regulation and considered that, in the circumstances, it provided a useful safeguard in the early stages of a PBR plan.[987]

795. Fortis and the ATCO companies proposed including an ESM in their PBR plans. Additionally, the UCA, the CCA and Calgary supported the inclusion of ESMs in the companies' PBR plans.

796. Fortis proposed a symmetrical deadband range of 100 basis points above and below the approved ROE. Any return within 100 basis points of the approved ROE would not be shared with customers, and any shortfall up to 100 basis points below the approved ROE would not be recovered through a subsequent rate adjustment. However, any return above the 100 basis point threshold would be shared equally with customers by way of a rate reduction in the following year, while any shortfall below the 100 basis point threshold would be shared equally with customers by way of a rate increase in the following year. Under the Fortis proposal, the PBR plan would be re-opened and reviewed if the achieved ROE is more than 300 basis points above or below the approved ROE in one year.[988]

797. Fortis stated that "given that this is the first time that FortisAlberta is applying for a PBR plan, an ESM will serve as a safeguard to buffer the earnings results during PBR implementation, in a manner beneficial to both customers and the Company."[989]

798. When asked by the Commission how its PBR proposal would need to change if its ESM were eliminated, Fortis stated:

> FortisAlberta's PBR Proposal would not otherwise change if the ESM component were eliminated. The proposed re-opener mechanism is based on the actual ROE before the ESM is applied.[990]

799. ATCO Electric and ATCO Gas proposed an ESM in each of their plans similar to the Fortis proposal. However, the ATCO companies proposed a symmetrical deadband range of 200 basis points above and below the approved ROE. Any return within 200 basis points of the approved ROE would not be shared with customers, and any shortfall up to 200 basis points below the approved ROE would not be recovered through a subsequent rate adjustment. Actual results beyond the 200 basis point threshold would be shared equally with customers by way of a rate reduction or rate increase in the following year, as required.

800. Under the ATCO companies' proposals,[991] the PBR plan would be re-opened and reviewed if the achieved ROE is more than 300 basis points above or below the approved ROE, after accounting for the implementation of the ESM. Ms. Wilson for the ATCO companies described the relationship between the companies' ESM and the re-opener proposal as follows, "[g]enerally earnings-sharing mechanisms and reopener clauses are viewed more as ensuring that if some of the parameters in the plan haven't been completely specified correctly or if something unexpected comes out of the PBR plan that was not -- the plan somehow doesn't have the ability

[987] Decision 2009-035, paragraphs 280 and 281.
[988] Exhibit 100.02, Fortis application, paragraph 126.
[989] Exhibit 100.02, Fortis application, page 35, paragraph 121.
[990] Exhibit 219.02, Fortis, AUC-ALLUTILITIES-FAI-16.
[991] Exhibit 98.02, ATCO Electric application, paragraph 233; Exhibit 99.01, ATCO Gas application, paragraph 123.

to address, those mechanisms ensure that the plan will not result in extreme outcomes for either customers or the utility."[992]

801. In addition to the above, ATCO Gas added the following caveat regarding its ESM and weather deferral account:

> In the event that ATCO Gas no longer has a Weather Deferral Account (WDA) during the course of the PBR Plan, the ROE to be used [for earnings sharing] will be the actual utility ROE, including the effects of deviations from normal weather.[993]

802. ATCO Electric and ATCO Gas submitted in argument that their ESMs have sufficiently wide deadbands to address any blunting of efficiency incentives that an ESM might cause.[994] The ATCO companies did not propose any changes to their PBR plans if ESMs were not approved. Specifically, the ATCO companies indicated that, if their plans were not to include an ESM, the 300 basis point threshold for re-openers would remain unchanged.[995]

803. Initially, AltaGas proposed an ESM as part of its PBR plan.[996] AltaGas proposed a symmetrical ESM with 50/50 sharing of earnings between 100 and 200 basis points above and below the approved ROE and 60(company)/40(customer) sharing of earnings over 200 basis points above and below the approved ROE.[997] AltaGas also submitted that, if achieved earnings are significantly greater than the approved ROE (i.e., above or below 300 basis points for two consecutive years or above or below 400 basis points in a single year), customers or AltaGas may apply for a re-opening of the PBR plan.[998]

804. AltaGas initially indicated that, if there was no ESM, three adjustments to the PBR formula would be required. First, the rates at the beginning of the PBR period would need to be adjusted upward. Second, the Y and Z factors might need to be carefully evaluated, and perhaps more broadly defined, given the potential effect of higher risks on the willingness of AltaGas to fund capital and commit resources. Third, AltaGas stated that "provided the rate of return reflects the impacts of higher financial risks, the Company faces stronger incentives to increase efficiency, without a provision for earnings sharing. Under these circumstances, it would be appropriate to consider a stretch component to the X Factor."[999] During the hearing, AltaGas confirmed that it is prepared to dispense with an ESM in its PBR plan with the addition of a stretch factor of between 0.1 and 0.2 per cent.[1000]

805. EPCOR did not propose an ESM as part of its PBR plan. EPCOR argued that ESMs are not consistent with AUC PBR principles 1, 3, and 5.[1001] As part of its application, EPCOR stated that a pure price cap approach has several advantages over a price cap plan with an ESM,

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[992] Transcript. Volume 3, page 568, Ms. Wilson.
[993] Exhibit 99.01, ATCO Gas application, page 41, paragraph 118.
[994] Exhibit 631.01, ATCO Electric argument, paragraph 267 and Exhibit 632.01, ATCO Gas argument, paragraph 292; Dr. Carpenter, Transcript, Volume 7, page 1308, lines17 to 22.
[995] Exhibit 631.01, ATCO Electric argument, paragraph 269 and Exhibit 632.01, ATCO Gas argument, paragraph 294.
[996] Exhibit 110.01, AltaGas application, paragraph 89.
[997] Exhibit 110.01, AltaGas application, paragraph 89.
[998] Exhibit 628.01, AltaGas argument, page 67.
[999] Exhibit 247.01, AltaGas, AUC-ALLUTILITIES-AUI-16.
[1000] Exhibit 529.01, AltaGas letter on corrections and amendments to its incentive regulation application, 2012-04-18, page 4.
[1001] Exhibit 630.02, EPCOR argument, paragraph 238.

because a pure price cap plan provides for greater incentives for efficiency that are more aligned with those in a competitive market.[1002]

806. EPCOR pointed to Dr. Weisman's evidence, stating that the gains from a pure price cap plan should exceed those from a PBR plan with earnings sharing. A plan without an ESM would also largely eliminate concerns with respect to gaming. Dr. Weisman stated:

> First, consumers bear less risk under pure price cap regulation that under a PBR with earnings sharing because prices do not vary directly with either the costs or the earnings of the regulated firm. Second, at least as a theoretical matter, because the incentives for cost reducing innovation are more pronounced under pure price cap regulation, the X factor should be higher than under a PBR regime that incorporates earnings sharing, *ceteris paribus*. Third, the incentives for strategic cost shifting, cost misreporting and abuse are mitigated under a pure price cap regime and this further lessens consumer exposure to prices that may reflect higher costs associated with such inefficiencies. As a corollary to this third observation, the pure PBR framework obviates the need for regulatory intervention with respect to cost allocations under a shared services model as rates are invariant to changes in such allocations over the course of the PBR regime. Finally, as the ongoing administration of a pure price regime economizes on both Commission and company resources, consumers benefit from the flow through of such efficiencies in the form of lower prices over time.[1003]

807. When questioned by the Commission about how its PBR plan would change if an ESM were adopted, EPCOR stated:

> At a minimum, if an earnings sharing mechanism were added to EDTI's PBR Plan, EDTI's proposed stretch factor would need to be eliminated, EDTI's proposed X factor would need to be reduced (i.e., made more negative) and the proposed timeline for the annual rate adjustment process would need to be adjusted due to the significant regulatory burden that earnings sharing mechanisms entail.[1004]

808. Dr. Schoech for AltaGas argued that the determination of earnings to be shared would result in a situation akin to cost of service regulation. Dr. Schoech stated:

> The earnings-sharing formulas introduce a bit of cost of service – I emphasize a bit of cost of service back into the regulation because earnings sharings looks [sic.] at the actual rates of return that the company achieves which, in turn, are based upon the company's costs. A pure revenue per customer cap with no earnings sharing completely decouples rates from the utility costs. And it's the disincentive or the reduced incentives, I guess I should say, arise from that reintroduction of an element of cost of service.[1005]

809. The interveners generally supported ESMs as part of PBR plans. The UCA indicated that its proposed menu approach for the X factor, which has been described in Section 6.2, has an ESM embedded into the menu options. However, if the menu approach is not adopted for the X factor, the UCA supported adoption of the ESM approved for ENMAX,[1006] including

1002 Exhibit 103.02, EPCOR application, paragraph 16.
1003 Exhibit 103.03, EPCOR application, Appendix A: The EDTI PBR Framework: Commission Principles and Economic Foundations, paragraph 78.
1004 Exhibit 233.01, EPCOR, AUC-ALLUTILITIES-EDTI-16, page 49.
1005 Transcript, Volume 8, page 1376, lines 6 to 15.
1006 Exhibit 634.02, UCA argument, paragraphs 329 and 330.

independent verification of the ROE with attestation by an officer of the company, with the same filing requirements as established for ENMAX.[1007]

810. The CCA also recommended that the PBR plans include ESMs similar to ENMAX's asymmetrical ESM[1008] and that a corporate sign-off be required on any data relied upon for the calculation of the earnings to be shared.[1009]

811. Calgary recommended adoption of an ESM for ATCO Gas but proposed that it be asymmetrical, providing for a sharing only of earnings above the approved ROE. Calgary questioned whether an ESM with a deadband is genuinely a sharing with ratepayers that would meet AUC Principle 5 and the legislative requirements of the *Electric Utilities Act*. Calgary argued that the equitable sharing or allocation of benefits derived from utility incentives with customers is required under Section 120(2)(d) of the *Electric Utilities Act* and Section 45(1)(a) of the *Gas Utilities Act*.[1010]

812. ENMAX did not take a position on the inclusion of ESMs in the proposed PBR plans of the companies, other than to state that an ESM should be symmetrical. However, ENMAX commented on the operation of the ESM in its FBR plan. In its evidence, ENMAX stated that although the ENMAX ESM has benefited customers, it has not benefited the company due to the unexpectedly high costs to establish, review and independently verify its ESM calculations. This verification process resulted in additional filing requirements over and above the requirements under AUC Rule 005.

813. Parties also pointed to concerns with gaming in ascertaining the actual returns to be shared.[1011] ENMAX proposed that, if the Commission approves an ESM for the companies, the Commission should determine in advance the necessary information required to ensure customers are receiving their share of the benefits.[1012] In this regard, most parties agreed that AUC Rule 005 would be the best vehicle to measure annual earnings sharing.[1013] ATCO Electric and ATCO Gas stated that the Commission's current safeguards in AUC Rule 005 are sufficient to address any concerns with administration and gaming.[1014]

814. Ms. Frayer, in her evidence for Fortis, noted that ESMs have other benefits to counter the weakening of incentives. These include the avoidance of unscheduled regulatory interventions, such as windfall profit taxes or other forms of claw-back, which distort patterns of investment and return.[1015]

815. IPCAA stated that an annual sharing of benefits would not be necessary as "[a]n annual benefit-sharing calculation based on net income would require a review of all revenues and costs, since net income is a comprehensive financial calculation. This in turn would require detailed variance analysis by management and extensive review, knowing that litigation is a possibility. It

[1007] Exhibit 634.02, UCA argument, paragraph 338.
[1008] Exhibit 636.01, CCA argument, paragraph 337.
[1009] Exhibit 636.01, CCA argument, paragraph 341.
[1010] Exhibit 629.01, Calgary argument, pages 55 and 56.
[1011] Exhibit 298.02, Calgary evidence, paragraph 165; Exhibit 630.02, EPCOR argument, paragraph 13,
[1012] Exhibit 297.01, EPCOR evidence, paragraphs 41 to 45.
[1013] Exhibit 100.02, Fortis application, page 35, paragraphs 122-123; Exhibit 98.02, ATCO Electric application, pages 9-1-9-2, paragraph 228; Exhibit 629.01, Calgary argument, page 59 of 72.
[1014] Exhibit 631.01, ATCO Electric argument, paragraph 272 and Exhibit 632.01, ATCO argument, paragraph 297.
[1015] Exhibit 100.02, Fortis application, Performance Based Regulation Evidence attachment, page 82, lines 17 to 21

thus appears that annual benefits sharing could perpetuate the regulatory burden."[1016] IPCAA made no specific recommendations with respect to the structure of earnings sharing except to state that "any sharing calculations should occur at the end of the PBR period rather than annually" and that the scope of review should be clearly defined in advance.[1017]

Commission findings

816. The Commission generally agrees with Dr. Weisman and Dr. Schoech that PBR plans with an ESM provide weaker incentives for efficiency gains, in part because costs and rates are no longer completely decoupled. The Commission notes Dr. Weisman's concerns with respect to ESMs.

> And when I say that earnings sharing has problems, it has problems I think on both sides. I don't think, as I mentioned in my rebuttal testimony, it brings forth the best behaviour on the part of regulators or the firms they regulate. I think that there are incentives for cost misreporting; cost shifting; the incentives are blunted with regard to managerial effort, and the reason for that is that the firm bears the entire costs of its effort at reducing costs but only retains a share of the fruits from those efforts.[1018]

817. The Commission agrees with EPCOR, AltaGas, ENMAX and IPCAA that increased scrutiny on an annual basis would be required for earnings sharing and would result in a greater regulatory burden. Accordingly, the Commission is concerned that including an ESM in the PBR plans of the companies would not be consistent with the objectives of Principle 3 to reduce the regulatory burden over time.

818. In the Commission's view, the safeguards offered by an ESM do not outweigh the negative efficiency incentives that would be re-introduced into the PBR plan as a result of the incorporation of an ESM.

819. The Commission has approved safeguards in Section 8 of this decision that provide for a re-opening and review of the companies' PBR plans if the reported ROE of a company significantly exceeds the approved ROE or if the company experiences a significant shortfall in earnings. These safeguards are comparable to those provided for by an ESM but do not, in the Commission's view, exhibit the disincentives that arise with ESMs. The Commission finds that the safeguards set out in Section 8 are adequate to protect both the companies and consumers.

820. In addition, the Commission notes that the companies' reported earnings will generally vary, sometimes significantly, from year to year during the PBR term. The effect of this variability in earnings coupled with an ESM was demonstrated by the operation of ENMAX's ESM for transmission and distribution:

> EPC's customers benefited from $0.331 million of earnings sharing for Transmission in 2008 and $0.563 million of earnings sharing for Distribution in 2009. As EPC is forecasting that it will earn below the AUC approved ROE for the remainder of the FBR term for both Distribution and Transmission, EPC expects that there will be no earnings sharing payments for the period 2011 to 2013.[1019]

[1016] Exhibit 306.01, IPCAA Vidya Knowledge Systems Corp. direct evidence, page 10, lines 23-26.
[1017] Exhibit 306.01, IPCAA Vidya Knowledge Systems Corp. direct evidence, page 10, lines 23-29.
[1018] Transcript, Volume 9, page 1765, Dr. Weisman.
[1019] Exhibit 297.01, ENMAX evidence, paragraph 41.

821. The Commission finds that this volatility of earnings argues against the introduction of ESMs. This is because the company may have sufficient earnings in one year to trigger a sharing with customers and then experience earnings below the approved ROE in subsequent years but not sufficient to trigger a sharing of the shortfall with customers. This deprives the company of a reasonable opportunity to earn its approved ROE over the PBR term. Conversely, the company may have insufficient earnings in one year, triggering a sharing of the shortfall with customers and then experience earnings above the approved ROE in subsequent years but not sufficient to trigger sharing with customers. This results in customers paying rates higher than necessary to give the company a reasonable opportunity to earn its approved ROE over the PBR term.

822. Accordingly, the Commission finds that ESMs, as proposed by the parties, are not warranted as an additional safeguard and the disincentives they will introduce are inconsistent with the objectives of PBR.

11 Term

823. The PBR term establishes the period over which a company must operate under the parameters of the formula in the PBR plan.

824. All of the parties recognized that, in setting the term of a PBR plan, the Commission must achieve a balance between two competing interests, namely, ensuring that the term is long enough to permit the company to achieve and capture efficiencies but not so long that the company's revenues are substantially out of sync with costs. As NERA stated, "ultimately we base rates for North American ratepayers on cost, and while we want to -- while it is a praise-worthy pursuit to want to avoid a disruption of frequent base rate cases, it is hard over the course of years to base rates on cost if you don't once in a while look at the costs."[1020]

825. The Commission noted this relationship in Decision 2009-035, when it rejected ENMAX's application for a10-year term as too long and approved a seven-year term which, given the passage of time, resulted in a five-year operational FBR term.[1021]

826. Each of the distribution companies, with the exception of ATCO Electric, proposed a PBR plan with a five-year term. ATCO Electric proposed a term of four years; stating, among other reasons, that staggering the filing of a second generation PBR plan with other companies would ease the regulatory workload for both the company and the Commission.[1022] In addition, ATCO Electric,[1023] ATCO Gas[1024] and AltaGas[1025] also proposed an optional two-year extension to the term, exercisable at the companies' election. Fortis stated in argument that it was open to an extension if the plan was working well.[1026]

827. Some of the companies, in proposing the terms for their PBR plans, also requested some form of rebasing or adjustment for capital expenditures during the PBR term.[1027] The

[1020] Transcript, Volume 1, page 197, lines 11-16.
[1021] Decision 2009-035, paragraph 118.
[1022] Exhibit 205.01, AUC-AE-13(a).
[1023] Exhibit 632.01, ATCO Gas argument, page 9, paragraph 28.
[1024] Exhibit 205.01, AUC-AE-13(b); Exhibit 0212.02, AUC-AG-3(a).
[1025] Exhibit 110.01, AltaGas application, page 15, paragraph 54.
[1026] Exhibit 633.01, Fortis argument, page 12, paragraphs 50 and 51.
[1027] See Section 7.3.3.2.

Commission has addressed the treatment of capital expenditures and adjustments in Section 7.3 of this decision.

828. The CCA supported the companies' applied-for terms but stated that, if the Commission preferred a shorter term such as three or four years, the CCA would not be opposed. In its view, a shorter term could reduce or eliminate some of the requests for supplemental capital budgets with less concern about untoward safety or reliability consequences during the PBR term. Nonetheless, the CCA stated that, whatever term is determined by the Commission, the length of the plans should be consistent among all companies.[1028] With regard to the proposals from ATCO Electric, ATCO Gas, and AltaGas to include an extension option to their plans' term, the CCA stated that "extensions should be allowed only with the consent of most parties"[1029] and that, if the plan is viewed as a success by all parties, there could potentially be an extension for up to five years.[1030]

829. Calgary supported a term of five years[1031] for ATCO Gas and indicated that a five-year term coincides with the Commission's efficiency, fair return and simplicity principles.[1032] However, Calgary did not support a unilateral extension of the ATCO Gas five-year term proposal.[1033]

830. The UCA did not support pursuing PBR because it considered that the risks of implementation outweigh the benefits of doing so.[1034] However, accepting that the Commission may nonetheless move forward with PBR, the UCA recommended that, as a first generation plan, the Commission adopt a term of three years.[1035] A period of four years was proposed for the second generation. In both cases, the UCA also recommended the imposition of a mid-term assessment to examine the PBR plans to date and to structure the design of the next term.[1036] Dr. Cronin, on behalf of the UCA, also opposed term extensions.[1037]

831. IPCAA submitted that it is too early for the Commission to implement a full PBR plan, and limited its recommendation to what it considered would be a suitable term for its limited G&A PBR plan. IPCAA stated that its limited G&A PBR plan "could run for a two-year term so that a comprehensive plan could be initiated when the limited plan expires."[1038]

Commission findings

832. One of the purposes of PBR is to start with cost of service-based rates and then sever the link between revenues and costs as a means of strengthening incentives for the companies to seek productivity improvements, and achieve lower costs than would otherwise be realized under cost of service regulation. PBR regulation allows regulated prices to change without a review of the company's costs, thereby lengthening regulatory lag. This better exposes the companies to the types of incentives faced by competitive firms. However, periodic review of the plans will be

[1028] Exhibit 636.01, CCA argument, page 12, paragraph 33-38.
[1029] Exhibit 636.01, CCA argument, page 12, paragraph 35.
[1030] Exhibit 636.01, CCA argument, page 14-15, paragraphs 42-43.
[1031] Exhibit 298.02, Calgary evidence, page 29.
[1032] Exhibit 64.01, PBR Principles Bulletin 2010-20.
[1033] Exhibit 629.01, Calgary argument, PDF page 20.
[1034] Exhibit 634.01, UCA argument, paragraphs 28-53.
[1035] Exhibit 299.02, Cronin and Motluk UCA evidence page 14, lines 15-23.
[1036] Exhibit 634.01, UCA argument, page 12, paragraphs 68-71.
[1037] Transcript, Volume 17, page 3322, lines 1-17.
[1038] Exhibit 635.16, IPCAA argument, page 2, paragraphs 8-9.

required. What the correct timing of a review will be and what the nature of the review should be will depend on the circumstances at the time.

833. The length of a typical PBR term in North America is from three to five years after which there is typically a rebasing and a recalculation of rates.[1039]

834. During the proceeding, the Commission asked parties to explore options for establishing a term.[1040] One option which was considered was whether it was possible to implement an open-ended term where there is no fixed date for the end of the PBR plan. The utilities and interveners were asked whether or not they supported an open-ended term during the hearing.

835. While most parties agreed that an open-ended term would have a positive impact on incentives,[1041] they also considered this proposal to be problematic.[1042] No party supported such a proposal, particularly for a first generation PBR plan.[1043] Dr. Weisman, on behalf of EPCOR, stated, "I think you, more generally, see that [open-ended term] in second and third-generation plans than you do the initial ones."[1044] As well, NERA concluded that such a proposal would be impractical and in their experience, they had not seen such a proposal implemented by other North American regulators.[1045] The Commission agrees that an open-ended term for the first generation PBR plans is not warranted.

836. The Commission considers that a five-year fixed term for each of the PBR plans is reasonable. The Commission has chosen this period recognizing that some of the elements approved in the PBR plans in this decision are novel and this term is consistent with the typical term for PBR plans in North America. Although a shorter term tends to blunt the incentives for companies to identify and implement productivity improvements, the Commission has approved the inclusion of an efficiency carry-over mechanism to mitigate this effect.

837. The Commission does not approve the recommendation of the UCA for a mid-term review half-way through the PBR term because doing so effectively shortens the term to two years, thereby eliminating the benefits achieved from lengthening the regulatory lag.

838. In order to ensure that all utilities are treated consistently, the Commission rejects ATCO Electric's four-year term proposal and directs all companies to proceed with a five-year fixed term. The Commission denies the proposals of ATCO Gas, ATCO Electric and AltaGas for a unilateral option to extend their plan term.

839. The Commission will not make a determination at this stage as to how it will go forward following the end of the five-year term. As the Commission noted in its February 26, 2010 letter; "[t]he Commission will initiate a proceeding during the first PBR term to consider how the

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[1039] Exhibit 100.02, LEI evidence, pages 31-32, PDF page 97; Exhibit 103.02, EPCOR application, page 19, paragraph 45; Exhibit 205.01, AUC-AE-13(a); Exhibit 391.02, NERA second report, Table 3, page 30 for a comprehensive list of PBR term lengths in Canada and the United States; Exhibit 629.01, Calgary argument, calculated the NERA example plan average as 4.9 years.

[1040] Exhibit 80.02, NERA first report, PDF page 8.

[1041] Dr. Carpenter, Transcript, Volume 5, page 832; Ms. Frayer, Transcript, Volume 11, pages 2188-2189.

[1042] Ms. Frayer, Transcript, Volume 11, pages 2188-2189.

[1043] Dr. Carpenter, Transcript, Volume 5, page 832; Dr. Makholm, NERA, Transcript, Volume 1, page 197; Exhibit 636.01, CCA argument, page 15, paragraph 42.

[1044] Transcript, Volume 10, page 1826.

[1045] Transcript, Volume 1, page 197 at lines 9 and 22.

success of the PBR plan should be judged and how it might be re-initiated, or rates 're-based,' at the end of the initial five-year term in a way that minimizes potential distortions to economic efficiency incentives."[1046]

12 Maximum investment levels

840. The customer and retailer terms and conditions of electric distribution service form part of the distribution tariffs of the electric distribution companies. Over the PBR term, it is expected that there may be changes required to these terms and conditions of service. Among the elements in the terms and conditions of service of the electric distribution companies which may change are the maximum investment levels (MILs) and the service fee schedule. MILs are the maximum amounts of money that an electric distribution company can invest in a new service for a customer. This investment level is added to the electric distribution company's rate base. The remaining cost of a new connection, if any, must be supplied by the customer as a contribution.

841. Recently, the electric distribution companies, with the participation of stakeholder groups, developed a common approach to managing changes to MILs. This common approach was approved for Fortis,[1047] ATCO Electric,[1048] and EPCOR.[1049]

842. Gas distribution companies do not have MILs but do have specified customer contribution levels. The specified customer contribution levels for ATCO Gas can be found in Schedule C to its terms and conditions of service. AltaGas also provides for specific customer contribution levels as part of its terms and conditions of service.

843. Each of the distribution companies proposed an automatic adjustment to their MILs/customer contribution levels during the term of the PBR. AltaGas proposed that its customer contribution levels be adjusted annually by the I-X mechanism. With the exception of the residential and street lighting customer groups, Fortis also proposed that its MILs be indexed annually by the I-X mechanism. For the residential and street lighting customer groups, Fortis proposed an increase of I-X plus10 per cent.[1050] EPCOR proposed that the MILs would be included in its annual capital forecast in its capital factor (K factor) stating that its MILs would be based on the historical actual costs, adjusted to keep pace with forecast construction costs.[1051] ATCO Electric proposed that its MILs be adjusted by the I factor only because it considered that the I-X mechanism would not offset the effect of the company's investment. Rather, AE argued that increasing MILs by the I factor ensures future customers receive equitable company investment and mitigates intergenerational equity issues.[1052] Similarly, ATCO Gas proposed that its specified customer contributions be adjusted only by the I factor. Both ATCO Electric and ATCO Gas submitted that changes to MILs or customer contribution policies could have a material impact on whether future capital expenditures can reasonably be expected to be covered

[1046] Exhibit 1.01.
[1047] Decision 2010-309: FortisAlberta Inc., 2010-2011 Distribution Tariff – Phase I, Application No. 1605170, Proceeding ID No. 212, July 6, 2010.
[1048] Decision 2011-134: ATCO Electric Ltd., 2011-2012 Phase I Distribution Tariff, Application No. 1606228, Proceeding ID No. 650, April 13, 2011.
[1049] Decision 2010-505: EPCOR Distribution & Transmission Inc., 2010-2011 Phase I Distribution Tariff, Application No. 1605759; Proceeding ID No. 437, October 28, 2010.
[1050] Exhibit 100.02, Fortis application, page 53, paragraph 187-188.
[1051] Exhibit 238.01, UCA-EDTI-08 b).
[1052] Exhibit 631.01, ATCO Electric argument, page 64, paragraph 256.

by the I-X mechanism.[1053] Both utilities also argued that this proceeding is not the proper forum to address changes to MILs and customer contribution policies.

844. The UCA opposed ATCO Gas and ATCO Electric's proposals to adjust its specified customer contributions/MILs by I only and recommended that any adjustment be made by the I-X mechanism as, in its view, these costs should be subject to the same efficiency incentives as any other utility cost.[1054] Calgary also rejected ATCO Gas' proposal and recommended that ATCO Gas adjust its specified customer contributions by I-X. Neither the CCA nor IPCAA provided any specific comments or recommendations regarding customer contributions/MILs.

845. For ease of reference, a summary of the proposed treatment for adjusting MILs/customer contributions is provided in the table below:

Table 12-1 Summary of proposed maximum investment levels

Category	Fortis[1055]	ATCO Electric/Gas[1056 1057]	AltaGas[1058]	EPCOR[1059]	UCA[1060]	Calgary[1061]
Residential	I-X+10%	I	I-X	Part of K factor adjustments	I-X	I-X
Street lighting	I-X + 10%	I	I-X	Part of K factor adjustments	I-X	I-X
All other customers	I-X	I	I-X	Part of K factor adjustments	I-X	I-X

Commission findings

846. It is evident from the submissions that the electric distribution companies want to continue to manage changes to their MILs in accordance with the common approach that was reached among the companies and stakeholders. However, this common approach was developed and approved by the Commission under cost of service rate regulation.

847. The Commission has considered the submissions of ATCO Electric and ATCO Gas regarding changes to MILs or customer contribution policies and agrees that this is not the forum to determine such a policy. Customer contribution policy considerations will be addressed in a future generic proceeding as directed by the Commission.

848. However, with regard to providing for the automatic escalation of MILs and specific customer contributions during the PBR term, the Commission considers that these contributions should be escalated by I-X.

849. In Decision 2000-01,[1062] the Commission's predecessor, the Alberta Energy and Utilities Board stated "an appropriate contribution policy … provides a suitable balance to an unlimited

[1053] Exhibit 631.01, ATCO Electric argument, page 64, paragraph 256; Exhibit 648.02, ATCO Gas reply argument, page 149, paragraphs 540-543.
[1054] Exhibit 300.02, UCA evidence of Russ Bell at page 56, A52.
[1055] Exhibit 100.02, Fortis application, page 53, paragraph 188.
[1056] Exhibit 476.01, ATCO Electric rebuttal evidence, page 66, paragraphs 203-204.
[1057] Exhibit 632.01, ATCO Gas argument, page 87, paragraph 282.
[1058] Exhibit 628.01, AltaGas argument, page 60.
[1059] Exhibit 238.01, UCA-EDTI-08 b).
[1060] Exhibit 634.01, UCA argument, page 57, paragraph 314.
[1061] Exhibit 629.01, Calgary argument, page 52.

obligation to service by imposing economic discipline on siting decisions."[1063] The Commission agrees. As MILs increase, so do the capital costs of the companies. Therefore, MILs should be subject to the same incentives as other capital costs faced by the companies. As such, the Commission considers that to escalate MILs by I only removes incentives to seek additional efficiencies. This would be contrary to Principle 1 as incentives to seek efficiencies in the competitive market would be effectively lessened by escalating MILs by I only. Therefore, subject to the discussion of Fortis' MILs proposal below, the Commission directs that MILs be escalated by I-X throughout the PBR term.

850. Fortis proposed to escalate the MILs of residential (Rate 11) and street lighting (Rate 31) classes by an additional 10 per cent per year of the PBR term. The Commission finds that this proposal is consistent with Fortis' approach to MILs which was approved in Decision 2012-108 and necessary to bring its MILs in line with the other electric distribution companies.[1064] Therefore, the Commission directs that Fortis' MILs for these two classes be escalated by I-X plus 10 per cent per year throughout the PBR term.

13 Financial reporting requirements

851. Each utility proposed to file a copy of its Rule 005[1065] report in its annual PBR filing.[1066] AUC Rule 005 requires a utility to file schedules of financial and operational information including return on equity, detailed explanations of variances and audited financial statements complete with notes and an audit report. Under AUC Rule 005, all utilities are required to file their financial results by either May 1 for electric utilities or May 15 for gas utilities.

852. The UCA in its evidence noted that the minimum filing requirement (MFR)[1067] and general rate application (GRA) schedules, respectively filed by electric and gas utilities in their GRAs, provide much more detail than the Rule 005 schedules.[1068] Therefore, the UCA proposed that electric utilities be ordered to provide MFR schedules as part of their annual PBR filing, and that each gas utility file all the schedules included in its last GRA.[1069] The UCA argued that, if only the Rule 005 schedules were to be filed throughout a utility's PBR term, rebasing at the end

1062 Decision 2000-01: ESBI Alberta Ltd., 1999/2000 General Rate Application Phase I and Phase II, Application No. 990005, File Nos. 1803-1, 1803-3, February 2, 2000.
1063 Decision 2000-01, page 270.
1064 Decision 2012-108, paragraphs 104-105.
1065 Rule 005: *Annual Reporting Requirements of Financial and Operational Results* (Rule 005).
1066 Exhibit 110.01, AltaGas PBR application, paragraphs 109 and 122; Exhibit 631.02, ATCO Electric argument, paragraph 328 and Exhibit 476.02, ATCO Electric rebuttal evidence, paragraphs 208-213; Exhibit 632.01, ATCO Gas argument, paragraph 343 and Exhibit 472.02, ATCO Gas rebuttal evidence, paragraphs 152-154; Exhibit 633.02, Fortis argument, paragraph 288(88); Exhibit 103.02, EPCOR PBR application, paragraph 256.
1067 The minimum filing requirements were approved in Decision 2007-017: EUB Proceeding, Implementation of the Uniform System of Accounts and Minimum Filing Requirements for Alberta's Electric Transmission and Distribution Utilities, Application No. 1468565, March 6, 2007. This decision was the culmination of a consultation to determine a uniform system of accounts for electric utilities to implement, and the minimum filing requirements electric utilities must comply with in their general rate applications. See USA & MFR on the AUC's website under Items of Interest.
1068 Exhibit 300.02, UCA evidence, Question 60.
1069 Exhibit 634.02, UCA argument, paragraphs 417 to 421.

of the term would be far more difficult and it would be far more difficult to return to cost of service regulation.[1070]

853. The UCA further argued that the continuity of actual data would be lost over a utility's PBR term if the companies were not required to file annually the more detailed MFR and GRA schedules. This is because companies subject to the MFR are required to provide only two years of actual data in a cost of service general rate application.[1071]

854. Fortis and the ATCO companies argued being required to file the MFR and GRA schedules on an annual basis would increase regulatory burden.[1072] The UCA responded that the additional cost to provide the extra detail in the MFR and GRA schedules would be minimal.[1073] IPCAA stated that customers have paid and are paying for data collection in the USA/MFR format and should be afforded the right to receive all such data on an ongoing basis.[1074]

855. The UCA also recommended that "all utilities continue to exclude costs previously disallowed from the calculation of actual results and ROE during the PBR term."[1075] The UCA proposed that, to address its concern with respect to excluding disallowed costs, companies should file the two tables it had provided in ENMAX's FBR proceeding and which ENMAX was subsequently directed to provide in its annual rate applications. These two tables consist of a reconciliation of financial and utility returns, and a summary of disallowed and inappropriate costs.[1076]

13.1 Audits and senior officer attestation

856. AUC Rule 005 requires a reconciliation of the utility's financial results to its audited financial statements. Audited financial statements are intended to provide independent assurance on the accuracy and completeness of a utility's financial results. AUC Rule 005 does not require an audit of the Rule 005 schedules themselves. Because of disallowed costs, non-regulated operations, changes in accounting policies and other factors, the financial results reported by a utility in its audited financial statements may be different than those reported in AUC Rule 005 or may differ over several years.

857. AltaGas, in its application, proposed that as part of its annual rate application it would provide a senior officer attestation, in addition to a copy of its Rule 005 filing (which includes audited financial statements).[1077] AltaGas' proposed senior officer attestation appears to be based on the nine issues that the Commission directed ENMAX to have reviewed and commented on by an independent auditor in Decision 2010-146.[1078] The attestation by an AltaGas senior officer would provide assurance as to the veracity of the reported numbers and the calculations used, and transparency with respect to any changes in methods, policies or parameters affecting the reported results.

[1070] Exhibit 634.02, UCA argument, paragraph 420.
[1071] Exhibit 634.02, UCA argument, paragraph 419.
[1072] Exhibit 644.01, Fortis reply argument, paragraphs 174 and 175; Exhibit 648.02, ATCO Gas reply argument, paragraphs 529 and 530; Exhibit 647.01, ATCO Electric reply argument, paragraph 354.
[1073] Exhibit 300.02, UCA evidence, Question 65 on page 67.
[1074] Exhibit 642.01, IPCAA reply argument, paragraph 19.
[1075] Exhibit 634.02, UCA argument, paragraph 422.
[1076] Exhibit 300.02, UCA evidence, Question 69 and Question 70.
[1077] Exhibit 110.01, AltaGas Incentive Regulation application, paragraph 123.
[1078] Decision 2010-146: ENMAX Power Corporation, Decision 2009-035 Formula Based Ratemaking Compliance Application, Application No. 1604999, Proceeding ID. 191, April 22, 2010, paragraph 132.

858. The Commission in Decision 2009-035 directed ENMAX as follows:

> … to have its reported ROE independently verified and to have an officer of the company attest to its validity. The Commission also directs EPC to include in its annual filings the reconciliation tables proposed by UCA.[1079]

859. Subsequently, in Decision 2011-260, the Commission directed ENMAX to provide attestations and certifications by one of its senior officers for the following matters:[1080]

- that the numbers, assumptions and presentation of the numbers in the application are accurate, complete, and proper
- regarding the accuracy and/or completeness of the nine issues identified
- that the numbers, assumptions and proposed rates are reasonable, fair and accurate

Commission findings

860. The Commission agrees that the utilities' proposal to include the AUC Rule 005 schedules in their annual PBR filings is reasonable and accordingly directs each company to include in its annual PBR filing a copy of its AUC Rule 005 filing.

861. To maintain transparency and consistency, the Commission agrees with the UCA that disallowed costs should continue to be identified and excluded from a company's ROE. The Commission directs each utility to include in its annual PBR rate adjustment filing a schedule including the two UCA tables put forth by the UCA.[1081]

862. The Commission directs each company to include in its annual PBR rate adjustment filing an attestation signed by a senior officer of the company as proposed by AltaGas. The senior officer attestation should include, as applicable, not only those items proposed by AltaGas, but also certifications on the accuracy, completeness and reasonableness of the numbers and assumptions included in the company's application. The required attestations and certifications by a senior officer of each company are as follows:

- confirm the reported ROE used to determine if a re-opener exists, either actual or weather normalized
- describe any changes in accounting methods, including assumptions respecting capitalization of labour and overhead and associated impacts
- describe any changes in the depreciation parameters and associated impacts
- describe any changes in the allocation of shared services costs and associated impacts
- confirm the inflation parameters used, including calculation and application of the rates formula to rates
- confirm the calculation of flow-through costs (Y factors) and associated riders conform to Commission directions
- confirm the calculation of exogenous (Z factor) adjustments and associated riders conform to Commission directions

1079 Decision 2009-035, paragraph 283.
1080 Decision 2011-260: ENMAX Power Corporation, 2011 Formula Based Ratemaking Annual Rates and Technical Report, Application No. 1607203, Proceeding ID No. 1169, June 20, 2011, paragraph 58(5).
1081 Exhibit 300.02, UCA evidence, page 74.

- confirm the calculation of capital trackers (K factor) and associated riders conform to Commission directions
- identify any material changes in the components of costs or revenues
- confirm that the numbers, assumptions and presentation of the numbers in the application are accurate, complete, and proper
- confirm that the numbers, assumptions and proposed rates are reasonable, fair and accurate

863. For a company under PBR, the requirement to file the AUC Rule 005 schedules in both its annual PBR rate adjustment filing and a separate AUC Rule 005 application, does not exempt the company from its obligation to maintain detailed accounts in accordance with the acts, regulations, Commission rules, or Commission decisions applicable to the company. Therefore, unless otherwise directed or exempted by the Commission, the companies are directed to maintain the ability to file a complete set of MFR and GRA schedules with actual results for all years within the term of the company's PBR plan. The companies are not required, however, to file a complete set of MFR and GRA schedules annually.

14 Service quality

864. Whereas an I-X mechanism creates efficiency incentives similar to those in competitive markets, it does not create incentives to maintain quality of service. In a competitive market, poor service quality will cause customers to switch companies, but poor service quality will not result in a loss of customers for a monopoly. The fact of monopoly supply of an essential public service has required regulators to monitor and regulate service quality. The Commission has recognized from the outset of its rate regulation initiative that the creation of greater efficiency incentives through adoption of a PBR plan also creates concerns that the resulting cost cutting might lead to reductions in quality of service. It is for this reason that the adoption of PBR typically coincides with the development and adoption by regulators of stronger quality of service regulatory measures when needed.

865. The Commission has the legislative authority under both the *Electric Utilities Act*[1082] and the *Gas Utilities Act*[1083] to make rules respecting service standards for electric utilities and for gas distributors. The Commission is also authorized to investigate compliance with the rules respecting service standards and, if necessary, is empowered to take steps to enforce them. This authority exists regardless of the type of ratemaking regime in operation, be it cost of service or performance-based regulation.

866. The first of the five principles (Principle 1) states, "A PBR plan should, to the greatest extent possible, create the same efficiency incentives as those experienced in a competitive market while maintaining service quality." All of the companies provided assurances in their submissions that service quality would not decline with the adoption of their proposed PBR plans. Notwithstanding these assurances, each of the interveners identified service quality degradation as a significant risk under PBR.[1084]

[1082] *Electric Utilities Act*, Section 129.
[1083] *Gas Utilities Act*, Section 28.3.
[1084] Exhibit 634.01, UCA argument, paragraph 368; Exhibit 307.01, PEG evidence for CCA, PDF page 65; Exhibit 635.01, IPCAA argument, paragraph 53; Exhibit 629.01, Calgary argument, PDF page 64.

867. In his evidence submitted on behalf of the UCA, Dr. Cronin reported the results of a study where he compared reliability statistics from Alberta electric distribution companies with selected companies in Ontario and the United States. Of the 22 companies Dr. Cronin described as higher density, ENMAX and EPCOR ranked first and third respectively for reliability. Among the lower density companies, Dr. Cronin described ATCO Electric and Fortis as having "superior reliability" compared to the 10 companies he examined. Dr. Cronin concluded from this analysis that "the AUC must be careful that the gains achieved to date are not put at risk for what could be limited potential gains under PBR."[1085]

Commission findings

868. The Commission has reviewed the service quality and reliability annual reports of the companies and agrees with the UCA that the service levels currently provided by the companies are acceptable.[1086] The Commission will require the companies to maintain their current levels of service quality throughout the PBR term.

14.1 Mechanism to monitor and enforce service quality

869. Currently, the Commission monitors service quality performance through AUC Rule 002.[1087] AUC Rule 002 sets out the service quality reporting requirements for electric utilities and gas distributors. Pursuant to this rule, all gas distributors and electric utilities under the jurisdiction of the Commission are required to file quarterly and annual performance reports.

870. Parties were divided as to whether the Commission should continue to use AUC Rule 002 for monitoring service quality along with an enforcement mechanism such as administrative monetary penalties, or whether the Commission should implement a performance standard mechanism within the PBR plan itself that also includes penalty adjustments for non-compliance in the formula. This latter approach, which is often referred to as a "Q factor" in the PBR formula, was adopted by the Commission in Decision 2009-035 for the ENMAX FBR plan. In the ENMAX FBR, the service standards were set out for the FBR plan and the penalties for failure to meet the standards were included as an adjustment to the formula.[1088]

871. ATCO Electric, ATCO Gas, AltaGas and Fortis favoured continued use of AUC Rule 002 for service quality reporting.[1089] The UCA stated that "Rule 002 should form the basis for service quality reporting under PBR."[1090] The CCA supported this approach.[1091]

872. EPCOR was in favour of the approach approved for the ENMAX FBR plan. In its view, AUC Rule 002 has significant limitations including the fact that it did not set out specified penalties, and it used the All Injury Incidence Frequency Rate metric instead of the Total Recordable Injury Frequency Rate metric that EPCOR proposed. EPCOR also argued in favour of its proposal because AUC Rule 002 applies only to owners of electric distribution systems and

1085 Exhibit 299.02, Cronin and Motluk UCA evidence, PDF pages 11-12.
1086 Service quality and reliability annual reports on AUC website.
1087 AUC Rule 002: *Service Quality and Reliability Performance Monitoring and Reporting for Owners of Electric Distribution Systems and for Gas Distributors*, effective date July 1, 2010 (Rule 002).
1088 Decision 2009-035: ENMAX Power Corporation, 2007-2016 Formula Based Ratemaking, Application No. 1550487, Proceeding ID. 12, March 25, 2009, paragraphs 302-304.
1089 Exhibit 631.01, ATCO Electric argument, paragraph 284; Exhibit 632.01, ATCO Gas argument, paragraph 306; Exhibit 628.01, AltaGas argument, PDF page 80; Exhibit 474.01, Fortis rebuttal evidence, paragraph 58.
1090 Exhibit 634.01, UCA argument, paragraph 369.
1091 Exhibit 636.01, CCA argument, paragraph 357.

to gas distributors but not to transmission, whereas, EPCOR's proposal, like that of ENMAX, included metrics for transmission.[1092] EPCOR's proposal to adopt the approach approved for the ENMAX FBR aligned with EPCOR's proposal to include transmission in its PBR plan.

873. IPCAA was also critical of adopting AUC Rule 002 as, in its view:[1093]

> Traditional service quality metrics such as those contained in AUC Rule 002 have been accepted in the context of traditional rate-base regulation. For example, SAIDI [System Average Interruption Duration Index] and SAIFI [System Average Interruption Frequency index] provide a broad sense of "position in the pack," relative to other utilities across Canada (and elsewhere), but that is all the precision that they can potentially provide. [T16:3039.3].They are biased metrics, which over-report some phenomena and under-report other phenomena. [T16:3061.22]
> …
>
> Since these metrics are based on number of customers affected, they can lead to poor incentives. For example, a utility might have two projects to reduce these metrics: one to trim trees around ten summer cottages and one to maintain ten large sites' high voltage equipment. If optimizing to cost and CAIDI [Customer Average Interruption Duration Index] was the goal, the cottage project might seem far superior even though the social and economic costs of outages to the large sites are much greater. [T16:3039.6]
> …
>
> AUC Rule 002 does not provide for any financial incentives, and the penalties provided by the EUA [sic. AUCA] at section 63 do not allow for a performance bonus. A symmetrical incentive plan would therefore have to be incorporated into the PBR plans. [T06, p.1090.22]

874. Calgary also rejected the use of AUC Rule 002, because it generally requires ATCO Gas to report its operations, rather than requiring the company to meet "specific performance criteria or standards."[1094]

Commission findings

875. The Commission has considered the advantages and the disadvantages of each of the two alternative proposals for monitoring and enforcing service quality: to continue to use AUC Rule 002 for monitoring service quality along with an enforcement mechanism such as administrative monetary penalties, or to implement a performance standard mechanism within the PBR plan itself that also includes penalty adjustments for non-compliance in the formula.

[1092] Exhibit 630.02, EPCOR argument, paragraph 296.
[1093] Exhibit 635.01, IPCAA argument paragraphs 50, 51 and 93.
[1094] Exhibit 629.01, Calgary argument, PDF page 65.

876. The following table sets out the metrics that are currently required to be reported by electric distribution utilities under AUC Rule 002 and indicates whether or not each metric has a defined target:

Table 14-1 Current AUC Rule 002 metrics for electric distribution utilities

Performance category	Metric	Defined targets
Billing and meter reading performance measures	Monthly billing and meter reading performance	No
	Cumulative meters not read within six months	Yes
	Identified meter errors	No
	Monthly tariff billing performance	Yes
Work completion performance measures	Energizing sites	No
	De-energizing sites	No
	Performing off-cycle meter reads	No
Worker safety performance measures	All injury/illness frequency rate	No
	Motor vehicle incident frequency	No
Reliability performance measures	System average interruption frequency index (SAIFI)	No
	Customer average interruption duration index (CAIDI)	No
	System average interruption duration index (SAIDI)	No
	SAIDI of worst-performing circuits on the system	No
Post-final adjustment mechanism (PFAM) adjustments processed	Post-final adjustment mechanism (PFAM) adjustments processed	No
Customer satisfaction measures	Percentage of customer satisfaction following customer-initiated contact with the owner	Yes
	Overall customer satisfaction measures	Yes
	Complaint response	Yes

877. The following table sets out the metrics that are currently required to be reported by gas distributors under AUC Rule 002 and indicates whether or not each metric has a defined target:

Table 14-2 Current AUC Rule 002 metrics for gas distributors

Performance category	Metric	Defined targets
Billing and meter reading performance measures	Cumulative meters not read within four months and one year	No
	Monthly tariff billing performance	Yes
Worker safety performance measures	All injury/illness frequency rate	No
	Motor vehicle incident frequency	No
Customer satisfaction measures	Percentage of customer satisfaction following customer-initiated contact with the owner	Yes
	Overall customer satisfaction measures	Yes
	Complaint response	Yes

878. The Commission also monitors call centre statistics, such as call answer time and abandon rates, in AUC Rule 003: *Service Quality and Reliability Performance Monitoring and Reporting for Regulated Rate Providers and Default Supply Providers* (Rule 003) because, in Alberta, call centre and billing functions are performed by competitive retailers, regulated rate providers and default supply providers. The electric utilities and gas distributors generally only field emergency calls from customers or calls from retailers.

879. In addition to filing quarterly and annual performance reports, another AUC Rule 002 requirement is for the company to meet with the Commission at least once annually after submission of its AUC Rule 002 annual report to discuss:

- service quality issues
- trends in service quality data reported by the owner, including any corrective action plans proposed by the owner to remedy failing performance standards
- issues raised by customer complaints filed with the Commission
- other policy issues related to customer service[1095]

880. In the Commission's view, using AUC Rule 002 together with a penalty provision has the following advantages:

- As a rule, the performance metrics already included in AUC Rule 002 were developed and updated in consultation with industry stakeholders.
- Continuity of the metrics and how they are reported will allow for trend analysis, especially for those metrics which have been in place since 2004. The Commission can rely upon historical databases to identify any negative trends in service quality and take corrective action if service levels decline.
- Companies may make decisions and take actions during the PBR term which may have consequences not readily apparent during the term. Using AUC Rule 002 will enable the

[1095] AUC Rule 002, Section 2.3.

Commission to monitor the consequences of those actions after the PBR term expires, regardless of the rate-setting mechanism in place after the end of the term.

- As is discussed further in Section 14.2, if AUC Rule 002 is accompanied by a penalty provision rather than including penalties as an adjustment to the PBR formula, unexpected and potentially undesirable impacts to consumer behaviour can be avoided. For example, if rates were lowered because of a penalty that adjusted the formula, certain price sensitive consumers may react by choosing to consume more energy which, in turn, could potentially increase revenues for the company. In such an event, incurring a penalty may result in a financial benefit to the company.

881. Having considered both the advantages and disadvantages of the two mechanisms proposed, the Commission finds that adopting AUC Rule 002 to determine performance standards and targets, and applying penalties in the event of non-compliance with the performance targets established, is the best approach for ensuring that the companies have an adequate incentive to maintain service quality under PBR.

882. The Commission is satisfied that, with the addition of new metrics and with the establishment of defined targets for those metrics currently without them, AUC Rule 002 will satisfactorily address the requirement for service quality measurement and reporting under PBR. As the Commission has determined in Section 2.4 of this decision that it will not include transmission as part of any PBR plan, it will, therefore, not be necessary to develop any performance measures for transmission at this time.

883. Accordingly, the Commission will initiate a consultation process before the end of 2012 to review and revise AUC Rule 002 in a timely manner. The companies and interveners will be invited to participate in the consultation process.

14.2 Penalties and rewards

884. AUC Rule 002 does not include provisions for penalties in the event that performance standards are not met. All parties agreed that some kind of enforcement mechanism is necessary. None of the companies argued against penalties for failure to meet service quality targets, when the failure was within their control.[1096]

885. Calgary recommended penalties and stated "the PBR plan should include direct fines paid by the utility for specific infractions; the fines should be treated as an addition to the next ESM payment or at the end of the PBR term."[1097]

886. The UCA recommended specified penalties of 10 per cent of earnings and stated:

> In a competitive market, poor performance is met with a lawsuit or more likely the loss of a customer, without any process to explain the reason for poor performance. As customers of a regulated utility have no choice to change suppliers, a specified penalty, with certainty as to the impact of poor performance is simpler to administer. Also, there

[1096] Exhibit 219.02, Fortis response to AUC-FAI-020 ALLUTIL (b), PDF page 35; Exhibit 628.01, AltaGas argument, PDF page 84; Exhibit 103.02, EPCOR PBR application, paragraph 91; Exhibit 631.01, ATCO Electric argument, paragraph 308; Exhibit 632.01, ATCO Gas argument, paragraph 326.

[1097] Exhibit 629.01, Calgary argument, page 63.

> is no evidence that customers want or are willing to pay for improved service levels, so the concept of a reward is not supported by the evidence.[1098]

887. IPCAA recommended a symmetrical approach to address service quality issues. That is, IPCAA proposed that penalties for degradations to service quality be instituted but also, if service quality improves, that a performance bonus plan be instituted.[1099]

888. EPCOR stated in its application that it "will explain the reasons for failing to meet the target as well as any future corrective actions EDTI proposes to take."[1100] While EPCOR only implied that the penalty would not apply if it adequately justified the failure, the other companies clearly argued for an opportunity to have their failures reviewed prior to a penalty being administered.[1101]

889. ATCO Electric and ATCO Gas expressed concerns that they would be penalized for events outside of their control and, therefore, recommended that, if they would be subject to penalties for events outside of their control, they should also be entitled to receive rewards where service targets are exceeded due to events outside their control in order to balance the increased risk, if penalties were automatic without opportunity for review.[1102] Fortis, in its application, did not request rewards for higher than standard service quality[1103] but on cross-examination recommended an approach with both penalties and rewards.[1104] AltaGas submitted that higher than required service quality levels should be met with rewards if a system of penalties is in place.[1105]

890. EPCOR proposed a reward for meeting its service quality standards throughout the five-year PBR term, to be specifically included in an efficiency carry-over mechanism for two years after the end of the PBR term.[1106]

891. Regarding the size of the penalties, ATCO Electric stated:

> The Commission makes the determination of whether a penalty is required and the appropriate amount would be commensurate with the benefit gained by the utility as a result of its actions.[1107]

892. ATCO Gas made a statement similar to the one made by ATCO Electric[1108] and continued:

> The magnitude of 10% of earnings recommended by the UCA is unreasonable. As ATCO Gas has already stated, there is a realistic likelihood that it will be penalized for events

[1098] Exhibit 649.02, UCA reply argument, paragraph 246.
[1099] Exhibit 635.01, IPCAA argument, paragraph 93.
[1100] Exhibit 103.02, EPCOR PBR application, paragraph 93.
[1101] Exhibit 628.01, AltaGas argument, PDF page 83; Exhibit 631.01, ATCO Electric argument, paragraph 306; Exhibit 632.01, ATCO Gas argument, paragraph 324; Exhibit 100.02, Fortis PBR application, paragraph 131.
[1102] Exhibit 647.01, ATCO Electric reply argument, paragraph 330; Exhibit 648.02, ATCO Gas reply argument, paragraph 502.
[1103] Exhibit 100.02, Fortis PBR application, paragraph 138.
[1104] Transcript Volume 11, page 2182.
[1105] Exhibit 650.01, AltaGas reply argument, paragraph 265.
[1106] Exhibit 103.02, EPCOR PBR application, paragraph 272.
[1107] Exhibit 647.01, ATCO Electric reply argument, paragraph 331.
[1108] Exhibit 648.02, ATCO Gas reply argument, paragraph 503.

> that were not within its ability to control. A penalty of 10% of earnings, which is in the order of $6 million for ATCO Gas, related to something ATCO Gas could not control is absurdly confiscatory. Penalties must not be so great as to have a significant negative impact on ATCO Gas' ability to recover its prudently incurred costs, including a Fair Return on its investments. The penalty should be commensurate with the benefit gained…[1109]

893. ATCO Electric, too, had concerns with having penalties as high as 10 per cent of earnings.[1110] Fortis and AltaGas did not discuss the size of the penalties in their final arguments or reply arguments.

894. EPCOR, however, proposed that a failure to reach any one service quality metric should result in a $250,000 penalty per year. Under EPCOR's proposed PBR plan, it would be penalized $1 million in 2013 if it failed to reach all four of its proposed metrics, and the $1 million would be escalated by I-X in subsequent years.[1111] However, EPCOR indicated that it would be applying to the Commission for an adjustment to two of its four performance targets and for relief from those targets for 12 months after implementation of its Outage Management System/Distribution Management System.[1112]

895. The UCA, in its reply argument, expressed concerns over EPCOR's proposal to be penalized $250,000 per failed target, stating:

> Further, having the penalty split between four measures, means that failing to meet one measure would result in a penalty of only $0.25 million, which is not material, and may not be sufficient to deter the conduct. It may well lead to the concern raised by the Chair that the utility will simply factor the fine into the economics of their decisions.[1113]

Commission findings

896. Section 129(3) of the *Electric Utilities Act* and Section 28.3(3) of the *Gas Utilities Act* provide the legislative authority for the Commission to take any or all of the following actions when the Commission is of the opinion that an owner of an electric utility or a gas distributor has failed or is failing to comply with its rules respecting service standards. These provisions state as follows:

> *Electric Utilities Act*
> 129(3) If the Commission is of the opinion that the owner of an electric utility has failed or is failing to comply with the rules respecting service quality standards, the Commission may by order do all or any of the following:
>
> (a) direct the owner to take any action to improve services that the Commission considers just and reasonable;
> (b) direct the owner to provide the customer with a credit, of an amount specified by the Commission, to compensate the customer for the owner's failure to comply with the rules respecting service quality standards;

[1109] Exhibit 648.02, ATCO Gas reply argument, paragraph 509.
[1110] Exhibit 647.01, ATCO Electric reply argument, paragraph 337.
[1111] Exhibit 630.02, EPCOR argument, paragraph 316.
[1112] Exhibit 630.02, EPCOR argument, paragraph 294.
[1113] Exhibit 649.02, UCA reply argument, paragraph 258.

(c) prohibit the owner from engaging in any activity or conduct that the Commission considers to be detrimental to customer service;
(d) impose an administrative penalty under section 63 of the *Alberta Utilities Commission Act*.

Gas Utilities Act
28.3(3) If the Commission is of the opinion that the gas distributor or default supply provider has failed or is failing to meet the service standards rules, the Commission may by order do all or any of the following:

(a) direct the gas distributor or default supply provider to take any action to improve services that the Commission considers just and reasonable;
(b) direct the gas distributor or default supply provider to provide the customer with a credit, in an amount specified by the Commission, to compensate the customer for the gas distributor's or default supply provider's failure to meet the service standards rules;
(c) prohibit the gas distributor or default supply provider from engaging in any activity or conduct that the Commission considers to be detrimental to customer service;
(d) impose an administrative penalty under section 63 of the *Alberta Utilities Commission Act*.

897. An administrative penalty under Section 63 of the *Alberta Utilities Commission Act* may require the person to whom it is directed to pay either or both of the following:

(a) An amount not exceeding $1 million for each day or part of a day on which the contravention occurs or continues.

(b) A one-time amount to address economic benefit where the Commission is of the opinion that the person has derived an economic benefit directly or indirectly as a result of the contravention.

898. The Commission considers that these legislative remedies provide the following benefits in dealing with a failure to maintain service quality standards during the PBR term:

- The potential size of the penalties under Section 63 along with the power to direct disgorgement of any economic benefits discourages service quality degradation.
- If service quality failures occur, the size of the penalty can be tailored to match the benefit gained by the company as a result of its action.
- The review process in administering the penalty allows the company the opportunity to explain the source or cause of the failure and argue that a penalty is not warranted or should be lessened.

899. The Commission rejects any proposal that a performance bonus should be available to the companies in the event that service quality targets are exceeded. As noted throughout this decision, the objective of a PBR plan is to incent behaviour that would be similar to that of a company in a competitive market. But, in a competitive market, a company may increase its service quality and charge a higher price, but risks losing customers. For monopoly utility companies, there is no risk of losing customers. Customers have no choice but to pay the higher

price for a service quality level that they may not want or cannot afford.[1114] Further, if the industrial customers that IPCAA represents want a higher level of service quality, they can elect to contract directly with the companies for that purpose at a negotiated price.

900. For the above reasons, the Commission will continue to rely on these legislative provisions, including the imposition of penalties, to address enforcement issues should service quality degrade.

14.3 Consultation process

901. The Commission in this decision is setting out directions for the AUC Rule 002 consultation for the following issues to assist parties participating in the consultation process:

a. Annual review meetings
b. Additional service quality metrics
c. Setting targets and penalties
d. Asset management reporting
e. Line losses (electric distribution companies only)

14.3.1 Annual review meetings

902. Parties provided their views on the format and content of the AUC Rule 002 annual review meetings. With respect to format, parties discussed the inclusion of interveners at the meetings, which previously only included the Commission and company staff. While some parties had no objection to including customer groups at the meetings,[1115] others expressed concern that such a change would be better addressed in a consultative process.[1116]

903. With respect to content, Fortis proposed expanding the scope of the review meetings to include an evaluation of outage causes and a discussion of asset management programs.[1117]

Commission findings

904. The Commission is not opposed to the inclusion of interveners at the annual review meetings. Proposed changes to the process and scope of the annual review meetings, including intervener attendance, will be further discussed in the upcoming AUC Rule 002 review consultative process referenced in Section 14.1, at which the roles of parties in the annual review meeting will be established.

14.3.2 Additional service quality performance metrics

905. Several interveners urged the Commission to adopt additional service quality performance metrics beyond those already identified under AUC Rule 002.

[1114] See discussion at Transcript, Volume 14, page 2892 to 2894.
[1115] Exhibit 628.01, AltaGas argument, page 79, Exhibit 631.01, ATCO Electric argument, paragraph 309, Exhibit 633.01, Fortis argument, paragraph 274.
[1116] Exhibit 629.01, Calgary argument, PDF page 68, Exhibit 648.02, ATCO Gas reply argument, paragraph 510, Exhibit 635.01, IPCAA argument, paragraph 94.
[1117] Exhibit 633.01, Fortis argument, paragraph 274.

906. The UCA recommended three new service quality performance metrics:

- service appointments met/time
- response time for emergency calls
- reconnect after cut off for nonpayment (CONP) response time[1118]

907. The CCA recommended that line losses be monitored and that additional metrics be put in place for transmission.[1119]

908. IPCAA was interested in having the following metrics or data sources included in the reporting requirements:

- system-level outage data
- outage information sent to customers as a part of the interval meter data set
- transmission measures[1120]

909. Calgary recommended that the Commission look to other jurisdictions for best practices and referenced the Gaz Métro Performance Incentive Mechanism Decision and Analysts' Presentation. The referenced document contains the following metrics:[1121]

- preventive maintenance
- emergency response time
- telephone response time
- meter reading frequency
- ISO 14001 (environmental management systems)
- greenhouse gas emissions
- customer satisfaction by customer class
- collection & service interruption procedure

910. EPCOR, ATCO Electric, ATCO Gas and Fortis did not favour the addition of the new metrics proposed by the UCA.[1122] AltaGas was not opposed to the addition of the metrics proposed by the UCA but indicated that any additions should be accomplished through a consultation process.[1123]

911. Fortis,[1124] ATCO Electric[1125] and EPCOR[1126] also opposed the addition of the metrics proposed by IPCAA.

[1118] Exhibit 634.01, UCA argument, paragraph 383.
[1119] Exhibit 636.01, CCA argument, paragraphs 358-360.
[1120] Exhibit 635.01, IPCAA argument, paragraph 59-75.
[1121] Exhibit 546.01, undertaking Carpenter to McNulty, PDF page 25.
[1122] Exhibit 630.02, EPCOR argument, paragraphs 305 and 306; Exhibit 631.01, ATCO Electric argument, paragraph 294; Exhibit 632.01, ATCO Gas argument, paragraph 316; Exhibit 633.01, Fortis argument, paragraph 263.
[1123] Exhibit 650.01, AltaGas reply argument, paragraph 259.
[1124] Exhibit 644.01, Fortis reply argument, paragraphs 158 and 161.
[1125] Exhibit 647.01, ATCO Electric reply argument, paragraph 321.
[1126] Exhibit 473.02, EPCOR rebuttal evidence, page 32.

Commission findings

912. The Commission has considered the recommendations of the parties as well as information they provided on the record of the proceeding with respect to the practices in other jurisdictions. Based on this review, the Commission considers that there is insufficient evidence for the Commission to make a determination as to whether it is in the public interest to impose the new metrics proposed by the parties. Therefore, the Commission will be seeking further information on the metrics proposed as additions to AUC Rule 002 in the upcoming AUC Rule 002 consultation process.

14.3.3 Target setting and penalties

913. Several parties recommended that the Commission adopt a specific approach to set targets for those metrics under AUC Rule 002 that do not currently have defined performance targets.

914. In his evidence for the UCA, Dr. Cronin recommended the use of a willingness-to-pay study to set a socially optimal level of reliability or, as Dr. Cronin explained, "the level of reliability where the marginal benefits from improvements equal the marginal costs of implementation."[1127] In testimony, Dr. Cronin described it as "trying to elicit from, say customers in this instance, how they value the reliability they receive from the company."[1128] Dr. Cronin also indicated in testimony that different customer classes would be willing to pay differing amounts for reliability improvements and that customers' willingness to pay would change over time.[1129]

915. In his rebuttal testimony on behalf of EPCOR, Dr. Weisman expressed his concerns with Dr. Cronin's recommendation:

> …this approach would seem to be ruled out by AUC PBR Principle 1: A PBR plan should, to the greatest extent possible, create the same efficiency incentives as those experienced in a competitive market while maintaining service quality. With this principle, the Commission has seemingly carved out a special exception for service quality. To wit, the AUC wishes to implement PBR regimes that replicate the incentive structure of a competitive market, "while maintaining service quality." Hence, even if service quality for Alberta utilities is currently over-provisioned from a social welfare perspective—service quality is "too good"—the Commission does not wish to see any fall off in the level of service quality that Albertans currently enjoy.[1130]

916. ATCO Electric also commented on Dr. Cronin's recommendation stating:

> ATCO Electric notes that the costs associated with providing the current level of service quality and reliability have been incurred and approved as prudent by the AUC, and cannot simply be undone if a WTP [willingness-to-pay] study indicates that the "socially optimal" level of service is something lower than the current level. While the results of these kinds of studies might be interesting, ATCO Electric is unsure of how they might actually be used and it is unclear as to how the costs of these studies will be addressed.[1131]

[1127] Exhibit 299.02, Cronin and Motluk UCA evidence, page 205.
[1128] Transcript, Volume 17, pages 3293-3296.
[1129] Transcript, Volume 17, pages 3293-3296.
[1130] Exhibit 473.09, rebuttal testimony of Dennis L. Weisman, Ph.D., pages 13-14.
[1131] Exhibit 631.01, ATCO Electric argument, paragraph 292.

917. For the interim period, prior to completion of the proposed willingness-to-pay research, the UCA proposed the following approach for setting targets:

> …the target for service levels should be based on current levels achieved. These are the levels included in going-in rates, and are the levels that customers are paying for. A five year average of actual achieved performance prior to the start of PBR is the best indication of the current level of performance achieved.[1132]

918. EPCOR,[1133] ATCO Gas[1134] and ATCO Electric[1135] argued that a target based on a simple five-year average would require improvements in service quality to avoid penalties half the time, and therefore the companies proposed setting a threshold of one standard deviation above the average to account for the volatility of the measurements due to factors outside of their control. In addition, EPCOR was concerned that the reporting of annual numbers against the five-year average plus one standard deviation would incent a company to further reduce its costs in years where it had no hope of achieving a performance target, since the poor measurement in one year would not impact future years' measurements. EPCOR, therefore, proposed that it report a five-year rolling average against the target so that "poor performance in one year would be reflected in the rolling average for the next four years, incenting the utility to continue to take steps and spend dollars to minimize the extent of its poor performance in the original year."[1136]

919. The UCA expressed concern over EPCOR's proposal to report a five-year rolling average, stating, "While I understand that an average will allow the impact of anomalies to be minimized, it will also mask any trends in degradation of service levels."[1137] In final argument, the UCA suggested that the removal of major events from the average would resolve the problem of volatility in the data and the likelihood of a penalty being imposed while service quality remained the same.[1138]

920. ATCO Gas and ATCO Electric rejected the UCA's suggestion to remove major events stating that removing " 'major events' just means that there is a requirement to make improvements over the current level on all other events."[1139] EPCOR provided a similar response and indicated that "service quality can be significantly impacted in a given year by varying volumes of smaller outages that, just like MEDs [major event days], are beyond EDTI's ability to control."[1140]

921. For the new service measures that the UCA wanted introduced, it stated that the measures should be tracked initially to establish a performance history because without history "there can

[1132] Exhibit 634.01, UCA argument, paragraph 381.
[1133] Exhibit 473.02, EPCOR rebuttal evidence, PDF page 21.
[1134] Exhibit 648.02, ATCO Gas reply argument, paragraph 493.
[1135] Exhibit 647.01, ATCO Electric reply argument, paragraph 316.
[1136] Exhibit 473.02, EPCOR rebuttal evidence, A12, PDF page 23.
[1137] Exhibit 300.02, UCA evidence of Russ Bell, A9, PDF page 14.
[1138] Exhibit 634.01, UCA argument, paragraph 382.
[1139] Exhibit 648.02, ATCO Gas reply argument, paragraph 494; Exhibit 647.01, ATCO Electric reply argument, paragraph 317.
[1140] Exhibit 646.02, EPCOR reply argument, paragraph 296.

be no meaningful targets set and therefore no penalties should be associated with the measures at this time."[1141]

922. The CCA, like the UCA, did not support setting a target with a standard deviation above average and recommended that "the performance measure, in each of the PBR test years, simply be the rolling average of the last 5 years of actual reported data."[1142] In other words, the target would change every year as the average changes over time.

923. In addition to concerns with the lack of a threshold above the average, EPCOR also argued that the CCA recommended approach "could result in degradation of service quality over time contrary to PBR Principle 1, as the targets could degrade as performance degrades."[1143] Fortis, ATCO Electric, ATCO Gas and AltaGas did not comment on the CCA's recommended approach.

924. Calgary in argument stated:

> There is no evidence on the record that ratepayers are seeking service levels superior to the existing service, particularly for residential and general commercial customers. Moreover, as was recognized by an AltaGas witness, the marginal cost of improving quality of service may well exceed the benefit.[1144]

925. IPCAA recommended "a consultative process be initiated to disclose what system-level outage data is retained by each utility, and explore efficient ways of using that data to set reliability targets and incentives."[1145]

926. An additional concern was raised by ATCO Electric,[1146] Fortis and EPCOR[1147] regarding how adjustments were to be made to setting targets as a result of the more accurate and detailed level of reporting that would be made available as a result of the implementation of their respective outage management systems. Fortis stated in testimony:

> So FortisAlberta is now implementing an outage management system. So whereas before we had 350 PLTs [power line technicians] independently inputting data manually, we will now move to a centralized process that will give us much better data, and that will cause SAIDI and SAIFI to increase, which if we'd stuck with the statistic itself, would imply the reliability has gotten worse, but reliability hasn't changed.[1148]

927. Similarly, EPCOR indicated that it would be applying for revisions to its SAIDI and SAIFI performance targets after it implements its outage management system.[1149]

1141 Exhibit 634.01, UCA argument, paragraph 384.
1142 Exhibit 636.01, CCA argument, paragraph, 371.
1143 Exhibit 646.02, EPCOR reply argument, paragraph 297.
1144 Exhibit 629.01, Calgary argument, PDF page 67.
1145 Exhibit 635.01, IPCAA argument, paragraph 60.
1146 Exhibit 631.01.AE-566, ATCO Electric argument, paragraph 297.
1147 Exhibit 630.02, EPCOR argument, paragraph 294.
1148 Transcript, Volume 11, pages 2179-2180.
1149 Exhibit 630.02, EPCOR argument, paragraph 294.

Commission findings

928. The Commission has evaluated the various proposals put forward by the parties to set targets. With respect to the willingness-to-pay study proposed by the UCA, the Commission does not consider that such a proposal is necessary. Although a willingness-to-pay study may provide valuable information if the Commission were trying to ascertain whether Alberta distribution companies were providing a socially optimal level of reliability, at this time, the evidence on the record of this proceeding demonstrates that reliability standards are acceptable. Customer satisfaction scores are already provided by the companies on an annual basis as a part of the AUC Rule 002 results. The Commission is of the view that declining customer satisfaction scores will be a timely indicator of problems. For all of these reasons, the Commission rejects the UCA’s proposal to use a willingness-to-pay study to set target measures at this time.

929. With respect to specific proposals of parties for setting service quality targets, the Commission will consider these proposals in the upcoming AUC Rule 002 consultative process.

930. In addition to establishing new measures and setting targets for those metrics currently without targets, the Commission considers that it is important that companies and Alberta customers understand the consequences that could result from a company’s failure to meet service quality targets. This is particularly critical if a pattern of consistent failure arises. Therefore, through the upcoming AUC Rule 002 consultation process, the Commission will develop a penalty structure for these metrics as part of the administrative penalty scheme authorized under Section 129(3) of the *Electric Utilities Act* and Section 28.3(3) of the *Gas Utilities Act*. The Commission expects that this penalty structure will include escalating penalty amounts commensurate with repeated violations of the targets up to and including the maximum administrative penalty set out in Section 63 of the *Alberta Utilities Commission Act.*

931. Following the completion of the consultative process the Commission will issue a bulletin indicating the process to be followed with respect to the adjudication of penalties including a hearing or other proceeding.

14.3.3.1 Asset condition monitoring

932. Service quality and the physical condition of assets are linked. Companies cannot provide consistently reliable service without a well-functioning physical infrastructure. Parties suggested that the Commission must determine whether it is sufficient to monitor only the resulting service quality or whether it is necessary to also monitor the actions of the companies to ensure that the companies do not maintain service quality during the PBR term, but reduce their costs by allowing certain assets to degrade as a result of aging and deterioration, to then be replaced in capital programs that have been delayed to the post-PBR period.

933. In the proceeding, a number of approaches were proposed that ranged from companies simply reporting their current practices for increased transparency to recommendations that advocated Commission and intervener involvement in the development of policies and best practices for the companies.

934. The UCA proposed that the Commission “direct utilities to develop and file an asset management framework using the asset management discipline as envisioned by The Woodhouse Partnership Limited (TWPL).”[1150] The UCA was not in support of the type of asset

[1150] Exhibit 634.01, UCA argument, paragraph 387.

management study being conducted by EPCOR, which the UCA classified as a study of asset condition.[1151]

935. IPCAA proposed to exclude power system assets from PBR until such a time as service quality and asset condition metrics can be developed[1152] through a Commission-led consultation process.[1153] IPCAA's proposal is to include only general and administration costs in PBR.

936. In response to IPCAA's proposal, the CCA stated:

> In our view, if the AUC is not inclined to adopt IPCAA's recommendation, the AUC should convene a consultative process which would review the existing practices and lead to a determination of appropriate asset-condition metrics with the goal the metrics so determined would be applicable for the balance of the PBR term.[1154]

937. Calgary stated that asset management and data disclosure should be addressed in a collaborative process.[1155]

938. All of the distribution companies were opposed to the increased regulatory burden that could result with having asset management as a part of PBR. AltaGas submitted that "the monitoring of asset condition may be of limited value, particularly given the different vintages and terrains applicable to different service territories which may impact the results of such surveys."[1156]

939. ATCO Gas indicated in its final argument that asset management metrics would hamper its ability to be innovative:

> How can ATCO Gas try to find innovative, efficient ways of doing things like valve inspections, for example, if it is required to meet a standard that specifies exactly how it will undertake those valve inspections? ATCO Gas agreed with Dr. Makholm that the measures need to be objective and measurable and focus more on the output of the utility.[1157]

940. In EPCOR's opinion, "a process to review and assess asset condition data would be extremely complex, time consuming and costly resulting in substantial additional costs being borne by rate payers."[1158]

941. ATCO Electric stated in its final reply argument:

> IPCAA recommends a consultative process be initiated to identify key asset condition data which should be provided by the utility to customers and the regulator. ATCO Electric views this request to be without merit as the provision of the data by itself is without value as it requires an engineering analysis and assessment within an overall

[1151] Exhibit 634.01, UCA argument, paragraph 388.
[1152] Exhibit 306.01, VIDYA Knowledge Systems evidence on behalf of IPCAA, PDF page 3.
[1153] Exhibit 306.01, VIDYA Knowledge Systems evidence on behalf of IPCAA, PDF page 13.
[1154] Exhibit 645.01, CCA reply argument, paragraph 216.
[1155] Exhibit 629.01, Calgary argument, page 66.
[1156] Exhibit 650.01, AltaGas argument, page 77.
[1157] Exhibit 632.01, ATCO Gas argument, paragraph 321.
[1158] Exhibit 630.02, EPCOR argument, paragraph 313.

> asset management program as was described by Ms. Bayley during testimony. This is completely contrary to the AUC principle of reducing regulatory burden."[1159]

942. In an excerpt from Fortis' testimony, Mr. Delaney stated:

> We have a million poles, 100,000 kilometres of line. Coming from that, we've developed a number of programs. We have a pole management program where we do life extension of poles, and we are embarking on an effort to get 1940s and 1950s vintage poles out of our system that have 30 percent or more failure rates. We have an underground cable management program where we rejuvenate and extend the life of underground cables, pad mount transformer maintenance program with predicted maintenance, oil sampling. Well, I can go on. We have switch maintenance. We have a number of programs associated with all of our assets… And I understand certainly the Commission's point of view on this that -- but it's a tough thing to regulate without, you know, violating Principle 3, given the complexity of all these things. Now, there are avenues. There is envisioned an annual meeting, whether it's under Rule 2 or some other aspect that could be sort of a technical conference thing could be added on where utilities can give -- well, probably give things like a breakdown of what's happened in reliability over the past year, which we kind of do right now under Rule 2 in terms of what happened. Another -- but it's going to be a very, very complex exercise to establish input measures and then what do you make of them once you've established them. The utility must have the flexibility to move within its asset maintenance program to do what needs to be done prudently. And if we were to introduce process that involves information responses and thousands of -- a big process like that, then my engineers and people that were looking to find innovation and find good things to do to reduce our costs will be -- we'll take that regulatory burden.[1160]

Commission findings

943. While the companies are opposed to the increased regulatory burden from the introduction of asset management monitoring practices, the Commission sees potential benefits from asset management reporting. The purpose of asset management monitoring is to provide increased visibility into the asset management practices of the companies. It is not to replace the management of assets by the companies. Indeed, IPCAA's witness, Mr. Cowburn, acknowledged that this was not the purpose of asset condition disclosure.[1161] Rather, regular reporting of asset condition will give the Commission and stakeholders some insight into the condition of the companies' assets. Information about asset condition will improve the Commission's ability to develop quality of service metrics as well as assess capital tracker applications as discussed in Section 7.3.

944. Having determined that some asset management monitoring will be required, the Commission is of the view that stakeholders and the Commission would benefit from an AUC consultative process to develop reporting requirements. This consultation will be separate from the process discussed above with respect to AUC Rule 002. The Commission anticipates that it will conduct a distribution company round-table on this matter after the commencement of the PBR term.

[1159] Exhibit 647.01, ATCO Electric reply argument, paragraph 326.
[1160] Transcript, Volume 11, pages 2177-2179.
[1161] Transcript, Volume 16, pages 3131 to 3132

945. The Commission will, after consultation with stakeholders, develop an asset management monitoring process to report on the condition of distribution assets with the intention of providing transparency while allowing the companies to manage their assets and operations. In so doing the Commission will seek to limit any additional regulatory burden.

14.3.3.2 Line losses

946. Electricity retailers are charged for all electricity entering the distribution system from the transmission system. Some electricity is lost as a result of the transfer of energy across electric distribution systems, including distribution lines, transformers and regulators. This lost electricity is referred to as technical losses.[1162] Other electricity may be consumed but not recognized as used or sold for a variety of reasons, such as meter reading errors, meters not read, unmetered sites incorrectly estimated and energy theft. This type of loss is referred to as unaccounted-for-energy or non-technical losses.[1163]

947. ENMAX filed a line loss proposal as a complement to its FBR plan. This proposal had been developed in discussion with a number of interveners and was approved by the Commission in Decision 2009-226. The proposal created an incentive for ENMAX to reduce levels of line losses and assume the risk from investments made to reduce the losses. If there were savings from the reduction in line losses, ENMAX and the customers shared equally in those benefits.[1164] ENMAX reported that, as a result of this incentive plan, $0.854 million has been saved by its consumers in 2009 and 2010.[1165]

948. On behalf of the UCA, Dr. Cronin stated that for line losses "we find that the Alberta LDCs again compare very well" to the Ontario LDCs.[1166] However, IPCAA, the UCA and the CCA all expressed concerns regarding the potential risk that line losses could increase from current levels under PBR.[1167]

949. IPCAA recommended that the way to address the potential risk that line losses may increase under PBR was to "mitigate the potential drivers of such increases." IPCAA elaborated by stating:

> If asset management processes are made available and equipment selection criteria can be reviewed in an open, consultative process, any changes in utility equipment specifications leading to higher losses will be known and understood as they occur… Information transparency is preferred over blanket requirements in order to maintain line losses at a specific level [CCA-Exhibit 636, page 123], as there may be a good economic justification for the selection of different equipment."[1168]

[1162] Exhibit 218.01, ATCO Electric IR responses to UCA, UCA-ALLUTIL-AE-4(ll), PDF page 35.
[1163] Exhibit 218.01, ATCO Electric IR responses to UCA, UCA-ALLUTIL-AE-4(ll), PDF page 35.
[1164] Exhibit 297.01, ENMAX evidence, PDF page16.
[1165] Exhibit 297.01, ENMAX evidence, PDF page16.
[1166] Exhibit 299.02, Cronin and Motluk UCA evidence, PDF page 11.
[1167] Exhibit 642.01, IPCAA reply argument, paragraph 60; Exhibit 299.02, Cronin and Motluk UCA evidence, PDF pages 183-185; Exhibit 636.01, CCA argument, paragraph 360.
[1168] Exhibit 642.01, IPCAA reply argument, paragraphs 60-61.

950. The UCA recommended that each applicant should develop a line loss proposal which should either involve a mechanism to adjust the rates or a set of incentives similar to the ENMAX approach.[1169]

951. The CCA submitted that EPCOR's plan should include:

> …a specific provision that its line losses during the PBR Term will not be any lower than that observed for the 3-year average period prior to the start of the PBR term i.e. average of 2.633% for the period 2009-2011, inclusive, per X239.01, UCA-ALLUTILITIES-4 (mm).[1170]

952. Fortis, EPCOR and ATCO Electric rejected the inclusion of a line loss proposal as suggested by the interveners. Fortis stated that it already "has ongoing system design and standards programs in place that focus on loss minimization, as well as an ongoing capital project that looks for loss reductions on specific lines. Any incremental line loss program would be duplicative and unnecessary."[1171] EPCOR expressed concern that it is already operating near the low end of what is physically achievable, that theft is outside of the direct control of the company and non-technical losses are already monitored by the AESO in support of AUC Rule 021: *Settlement System Code Rules* (Rule 021).[1172]

953. In its rebuttal evidence, ATCO Electric explained its engineering processes and the difficulty in isolating changes related to the reduction in line losses:

> ATCO Electric is not proposing to introduce a line loss module as it is unable to distinguish investments required to maintain the optimal operation of its distribution system from those that may provide a benefit to its line loss, which is a consequence of all the actions ATCO Electric undertakes. As the distribution network expands, ATCO Electric will continue to implement and deliver the appropriate types of distribution investment that considers all important aspects of ensuring a safe and reliable distribution system is in place. Failure of its duty will result in power quality and reliability degradation that will impact ATCO Electric's customers' ability to operate and connect to the distribution system. In addition, current Settlement System Code Rules under Rule 021 ensure utilities are aware and comply with specific unaccounted for energy tolerances that are monitored by the AESO.

Commission findings

954. The Commission considers that line losses are currently within acceptable levels. Nonetheless, the Commission has concerns about how PBR may provide incentives that have an adverse impact on line losses.

955. As a part of the consultative process to review and revise AUC Rule 002, the Commission will consider metrics for monitoring line losses and the establishment of targets for ensuring companies maintain their current levels of line loss performance. The Commission is also prepared to consider other approaches that parties may propose.

[1169] Exhibit 299.02, Cronin and Motluk UCA evidence, PDF pages 184-185.
[1170] Exhibit 636.01, CCA argument, paragraph 360.
[1171] Exhibit 644.01, Fortis reply argument, paragraph 178.
[1172] Exhibit 646.02, EPCOR reply argument, paragraphs 268-270.

14.4 Re-openers for failure to meet service quality targets

956. The UCA, the CCA, IPCAA and EPCOR each proposed that a re-opening of the PBR plan should be undertaken in the event that there is a dramatic decline in service quality.

957. In argument, both the UCA and the CCA recommended that failure to meet a specific performance standard for two consecutive years would be an issue that could trigger a re-opener.[1173] In the case of the CCA, the re-opener would be automatic or "alternatively at the request of an interested party or the AUC."[1174] IPCAA considered that if "customer service is materially degraded by any utility, the PBR plan should be re-opened or even terminated by an off-ramp."[1175] EPCOR's submission included a re-opener for failure to meet the same service quality target for two consecutive years and stated that adjustments to the PBR plan "could include such things as a change to the performance target, a change to the performance measure, or the termination of the measure."[1176]

958. Conversely, ATCO Gas and ATCO Electric were of the opinion that a re-opener clause that is linked to not achieving specific performance standards is not required, especially if service quality is addressed under AUC Rule 002[1177] while Fortis' proposed PBR plan did not include any provisions for re-openers or off-ramps as a result of service quality degradation.[1178]

Commission findings

959. The Commission has the ability under both the *Electric Utilities Act* and the *Gas Utilities Act* to make rules regarding service quality and to monitor and enforce those rules. If it should become apparent that the ways in which the companies are implementing their PBR plans are having a detrimental impact on service quality performance, the Commission can take whatever steps are necessary under the legislation to direct a change in behaviour without having to re-open the PBR plan. Accordingly, the Commission does not accept the proposal to include degradation in service quality as an event that would necessitate a re-opening of the PBR plans.

15 Annual filing requirements

960. The companies recognized a requirement for periodic filings to deal with various rate or capital factor applications during the PBR term. The proposals differed with respect to the number, content and frequency of applications. The companies were also in favour of maintaining existing application processes in respect of certain deferral accounts and flow-through accounts. In addition, some sections of this decision refer to PBR related annual filings under AUC Rule 002 and AUC Rule 005.

15.1 Annual PBR rate adjustment filing

961. Companies generally preferred an annual filing for the setting of the following year's rates. Some of the companies requested a second annual filing with respect to the true-up of

[1173] Exhibit 634.01, UCA argument, paragraph 321; Exhibit 636.01, CCA argument, paragraph 326.
[1174] Exhibit 636.01, CCA argument, paragraph 327.
[1175] Exhibit 635.01, IPCAA argument, paragraph 38.
[1176] Exhibit 103.02, EPCOR submission, paragraph 243.
[1177] Exhibit 648.02, ATCO Gas reply argument, paragraph 432; Exhibit 647.01, ATCO Electric reply argument, paragraph 278.
[1178] Exhibit 633.01, Fortis argument, paragraphs 221-233.

certain factors or amounts that would be included on a forecast basis in the annual rate application so as to adjust rates more than once each year. The Commission has determined above that a second rate adjustment adds unnecessary administrative complexity and is not required.

962. The Commission determines that the effective date for annual rate changes will be January 1st each year. In order to accommodate this date, a number of items will need to be considered leading up to the annual rate change. The annual PBR rate adjustment filing to establish the rates to be effective on January 1st of the upcoming year is to be made by September 10th of each year.

963. The annual PBR rate adjustment filings for electric distribution companies will calculate rates to be effective on January 1st of the upcoming year based on the following:

$$R_t = \underbrace{BR_{t-1}(1 + (I - X))}_{\substack{\text{Base rates} \\ (BR_t)}} +/- Z +/- K +/- Y$$

964. The annual PBR rate adjustment filings for gas distribution companies will calculate rates to be effective on January 1st of the upcoming year based on the following:

$$RPC_t = \underbrace{BRPC_{t-1}(1 + (I - X))}_{\substack{\text{Base revenue} \\ \text{per customer class}}} +/- Z +/- K +/- Y$$

$$R_t = RPC_t / BDC_t$$

Where:

R_t	=	upcoming year's rates for each class
RPC_t	=	upcoming year's revenue per customer for each class
BR_{t-1}	=	current year's base rates for each class
$BRPC_{t-1}$	=	current year's base revenue per customer for each class
BDC_t	=	billing determinants for each class for the upcoming year
I	=	inflation factor
X	=	productivity factor
Z	=	exogenous adjustments
Y	=	flow-through items, collected through Y factor rate adjustments (not including Y factors collected through separate riders)
K	=	capital trackers collected through K factor rate adjustments

965. The items to be included in the annual PBR rate adjustment filings will therefore be:

- base rates from the current year by rate class that will be the starting point for the upcoming year's rates
- I factor calculation as described in Section 15.1.1 with supporting backup

- Z factors approved during the previous 12 months calculated as described in Section 15.1.2
- K factor adjustment related to approved capital trackers calculated as described in Section 15.1.3
- Y factor adjustment to collect Y factors that are not collected through separate riders calculated as described in Section 15.1.4
- billing determinants for each rate class for gas applications
- billing determinants that will be used to allocate items that are not subject to the I-X mechanism to rate classes as described in Section 15.1.5
- backup showing the application of the formula by rate class and resulting rate schedules
- a copy of the Rule 005 filing filed in the current year
- any other material relevant to the establishment of current year rates

15.1.1 I factor

966. As discussed in Section 5.4, the I factor to be included in the annual PBR rate adjustment filings will be calculated using the Alberta AWE (average weekly earnings) from July of the prior year to June of the current year and the Alberta CPI (consumer price index) from July of the prior year to June of the current year. The companies will be required to provide Statistics Canada data for each index and show how the I factor was calculated.

15.1.2 Z factors

967. As noted in Section 7.2.2 some approved Z factor applications may generate costs or savings that can be fully recovered or refunded over a single year or portion thereof while other events will generate costs or savings requiring treatment over a longer term. The nature of the required Z factor rate adjustment will be considered by the Commission on a case-by-case basis in response to a Z factor application.

968. Where a Z factor adjustment has been directed to be included in rates as an adjustment to base rates, the company will make the required adjustment and provide details of the calculation as part of the annual PBR rate adjustment filing.

969. Where a Z factor adjustment has been directed to be included in rates but not as an adjustment to base rates and therefore outside of the I-X mechanism, each company will calculate a Z factor amount to be included in the annual PBR rate adjustment filing. All these Z factor amounts approved by the Commission since the last annual PBR rate adjustment filing will be aggregated as a single rate adjustment and included with the rate adjustment in the next annual PBR rate adjustment filing.

970. Parties should be aware of the Commission's performance standards for processing rate-related applications as prescribed by Bulletin 2010-16.[1179]

971. The most recent forecast of billing determinant information along with the Phase II methodologies in place, as discussed in Section 15.1.5 below, will establish the Z factor rate adjustments associated with the Z factor revenue requirements by rate class.

[1179] AUC Bulletin 2010-16, Performance Standards for Processing Rate-Related Applications, Table 1.

972. Due to the time lag that may occur between the occurrence of a Z factor event and implementation of the necessary rate adjustments, the companies will be permitted to record carrying charges calculated using an interest rate equal to the Bank of Canada's Bank Rate plus 1½ per cent, subject to any previously approved Commission procedure for awarding interest. This interest rate is consistent with AUC Rule 023,[1180] however the regulatory lag and materiality requirements of Rule 023 will not apply.

15.1.3 Capital trackers

973. The complexity of capital tracker applications will require that these applications be submitted earlier. To promote regulatory efficiency the Commission considers that a single annual capital tracker application filing for each company will be made by March 1st each year.

974. A single application must be filed by March 1st of the current year with respect to all projects which may qualify for capital tracker treatment to be commenced in the upcoming year. The timing of the application is intended to provide sufficient time for processing of the application and inclusion of approved amounts as a K factor in the September 10th annual PBR rate adjustment filing. All of the capital trackers for each company will be collected in a pool that comprises a single K factor in the PBR formula for the company. As discussed in Section 7.3.3.2, the process for filing upcoming projects and associated K factor amounts is only to establish interim K factor rate adjustments. Interim amounts will be subject to true-up to actual costs as part of a prudence review following completion of the project.

975. The annual March 1st capital tracker filing must include a business case with respect to each proposed capital tracker. The business case will include forecast costs, being the amount proposed to be collected on an interim basis through the K factor in the upcoming year. If a project is expected to carry into future years, forecasts for the future years should also be included in order to assess the scope and scale of the project including the materiality of the entire project to be considered. Multi-year forecasts will be updated each year in the capital tracker application so that the forecast amounts to be included that year's K factor will reflect the most recent information available. In addition, the March 1st capital tracker application shall true-up the costs of projects that have been completed since the prior year's capital tracker filing together with sufficient information to permit a prudence review of these completed projects. To facilitate a prudence review of a project, the company must submit information showing that it has completed the project in the most cost effective manner possible. This information will include the results of competitive bidding processes, comparisons of in-house resources to external resources, and any other evidence that may be of assistance in demonstrating the prudence of the expenditures.

976. The results of the prudence review and cost true-up will be an adjustment to the K factor included in the following year's rates. The companies will calculate the revenue requirements resulting from the actual capital tracker expenditures, and compare those to the forecast amounts that were collected on an interim basis in the prior year. The difference between the approved revenue requirements and the forecast revenue requirements for the prior year will form the basis for the K factor true-up rate adjustment. In addition, because the capital expenditures will remain in the tracker for the duration of the PBR term, the amounts to include in the capital tracker revenue requirement calculations in subsequent years during the PBR term will be based on the actual approved expenditures rather than the initial forecasts.

[1180] AUC Rule 023: *Rules Respecting Payment of Interest* (Rule 023), Section 3, paragraph 2, page 2.

977. The calculation of the K factor rate adjustments will be similar to revenue requirement calculations under cost of service, except that the calculation will be limited to the depreciation, taxes and return associated with the incremental rate base for the expenditures that form the capital tracker. The weighted average cost of capital rate to be used in calculating the revenue requirements associated with capital trackers will be based on current rates established in the most recent GCOC proceeding rather than using the rates that were in place at the start of the PBR term. The most recent forecast of billing determinant information along with the Phase II methodologies in place, as discussed in Section 15.1.5 below, will establish the K factor rate adjustments associated with revenue requirements by rate class.

978. As discussed in Section 7.3.4, the companies may file, as separate applications at the time of their compliance filing on November 2, 2012, applications for approval of specific 2013 projects as capital trackers, including projects that were included in their PBR filings. The companies need not re-file the information already on the record of this proceeding with respect to those capital projects included in their PBR filings. The companies may specifically refer to the record of this proceeding and supplement that information with additional information or explanations to address the Commission's capital tracker criteria.

15.1.4 Y factor rate adjustments

979. The forecasts for the provision for each Y factor item to be included in the upcoming year's rates will be included in the annual PBR rate adjustment filing. As discussed in Section 7.4.4 the provisions will generally be based on the 2012 test year of the general tariff application or general rate application proceeding that forms the going-in rates. The true-up of the Y factor accounts, being the difference between the prior year provision and the prior year actual result, will also be identified in the September 10th PBR annual filing.

980. For any Commission directed items (e.g., AUC assessment fees, intervener portion of hearing costs, etc.) and the UCA assessment fees, the basis for determining the true-up to be included in the annual PBR rate adjustment filing will be the actual amounts that were incurred from August 1 of the prior year to July 31 of the current year.

981. The true-up process will also capture the impact of any Commission directed items that occurred from September 1 of the prior year to August 31 of the current year that were new and for which there was no provision in the Y factor for the current year.

982. All of the Y factor accounts that are not subject to flow-through treatment and collected by way of a separate rate rider will be collected in a pool that comprises a single Y factor in the PBR formula for the company. The most recent forecast of billing determinants along with the Phase II methodologies in place, as discussed in Section 15.1.5 below, will establish the Y factor rate adjustments associated with Y factor revenue requirements by rate class.

983. Carrying charges on balances that are subject to true up will be calculated using an interest rate equal to the Bank of Canada's Bank Rate plus 1½ per cent, subject to any previously approved Commission procedure for awarding interest on accounts that existed prior to implementation of PBR. This interest rate is consistent with AUC Rule 023,[1181] however the regulatory lag and materiality requirements of Rule 023 will not apply.

[1181] AUC Rule 023, Section 3, paragraph 2, page 2.

15.1.4.1 Flow-through items

984. As discussed in Section 7.4.3, flow-through items currently collected by way of separate rider will be collected using the existing methodology and rider mechanism outside of the annual PBR rate adjustment filing process to recognize that these flow-through items are currently processed throughout the year. As a result, applications related to flow-through items may be submitted throughout the year.

15.1.4.2 Clearing balances in deferral accounts that are not permitted to continue under PBR

985. To the extent that the companies had deferral accounts under cost of service regulation that have not been approved to continue under PBR in this decision, the Commission recognizes that the companies may have residual balances in the deferral accounts that need to be disposed of. The Commission determines that the companies will submit an application identifying the outstanding balances as of December 31, 2012 as part of their annual PBR rate adjustment filing for 2013.

15.1.5 Billing determinants and Phase II implications

986. Under PBR, the portion of electric distribution rates subject to the I-X mechanism is not impacted by changes to billing determinants. The portion of gas distribution rates subject to the I-X mechanism is impacted by changes in usage per customer. Rate adjustments outside of the I-X mechanism (Z factors, K factors and Y factors) for both electric and gas distribution companies will involve calculating a total amount of revenue requirement associated with the underlying items, and then allocating that revenue requirement to rate classes to determine the necessary rate adjustments. This will require the use of billing determinants and Phase II rate class allocation methodologies. In addition, a number of the companies identified the possibility of Phase II applications to revise the rate class allocation methodologies that may be required during the PBR term, which would also require the use of billing determinants.

987. Fortis proposed to use to a method consistent with that used in previous cost of service filings to establish its billing determinants under PBR. Fortis provided a forecast of the billing determinants to be used for the entire PBR term, and indicated that it will accept the risk on any variances between forecasts and actual.[1182] Fortis identified the potential for a Phase II application to transition towards 100 per cent revenue-to-cost ratios by rate class, and the billing determinant forecast would be used for this purpose.[1183]

988. ATCO Electric also provided a forecast for billing determinants for the entire PBR term. ATCO Electric followed the same methodology for preparing the billing determinants and load forecasts used in its 2011 to 2012 GTA. In addition, if a Phase II application is determined to be necessary during the PBR term, ATCO Electric proposed to use the billing determinant forecast provided in its PBR application for input into the cost of service and rate design.[1184]

989. EPCOR proposed that billing determinants be reforecast annually using a calculation methodology that relies on readily available historical billing determinants.[1185] EPCOR identified that Phase II rate rebalancing adjustments may be required as a result of the implementation of a

[1182] Exhibit 100.02, Fortis application, Section 2, paragraph 37, page 10.
[1183] Exhibit 100.02, Fortis application, Section 13.2, paragraph 181, pages 50-51.
[1184] Exhibit 98.02, ATCO Electric application, Section 16, paragraphs 290-291, page 16-3.
[1185] Exhibit 103.02, EPCOR application, Section 2.3.7.1, paragraphs 156-158, pages 53-54.

new geographic information system (GIS).[1186] Aside from the aforementioned adjustment from the implementation of GIS, as a result of the characteristics of its PBR plan, EPCOR identified that Phase II applications will no longer be required in the normal course.[1187]

990. ATCO Gas indicated that it would be providing a billing determinants forecast each year. ATCO Gas proposed to use the principles outlined in its Phase II negotiated settlement approved in Decision 2010-291 to determine the rates for each year. ATCO Gas proposed to use the same methodology as long as the negotiated settlement remains in place. In the event that the negotiated settlement is terminated for any reason, ATCO Gas proposed that a new Phase II application be filed, with the expectation that the determination of rates for the remainder of the PBR term would be governed by the outcome of that proceeding.[1188] Calgary supported the Phase II proposal of ATCO Gas.[1189]

991. AltaGas proposed that its billing determinants be reforecast annually in order to capture any declining usage per customer.[1190] AltaGas anticipated filing a Phase II application for its 2013 to 2017 PBR plan that will involve preparation of a revised cost of service study and rate design based on the revenue requirement approved for 2012, and adjusted pursuant to the proposed PBR formula to collect the forecast 2013 revenue cap amount.[1191]

992. The UCA proposed that each utility should be required to file a Phase II application by the end of 2015 or at the latest 2016. The UCA noted that several of the companies are in the process of performing an analysis on cost allocations and that there are also previous Commission directions that are still outstanding, and as a result it will be necessary to realign rates in the middle of the PBR term.[1192] The CCA generally supported the position of the UCA.[1193] IPCAA stated that "[c]ustomers deserve just, fair and reasonable rates, and a Phase II rates review should not be delayed or deferred by PBR."[1194]

Commission findings

993. The Commission considers that billing determinants will have limited use during the PBR term for electric distribution companies because the I-X mechanism results in rate changes that are separated from the costs of the company, therefore there is no revenue requirement that needs to be allocated to rate classes using billing determinants as was the case under cost of service regulation. The revenue-per-customer cap plans approved for the gas distribution utilities will, however, require usage-per-customer forecasts based on current billing determinants to perform the annual customer rates calculations. In addition, both electric and gas distribution companies will be required to allocate items outside of the I-X mechanism including Z factors, K factors and Y factors to rate classes, and those allocations will require billing determinant forecasts and Phase II methodologies.

1186 Exhibit 103.02, EPCOR application, Section 4.3, paragraph 264, page 84.
1187 Exhibit 103.02, EPCOR application, Section 3.0, paragraph 232, page 77.
1188 Exhibit 99.01, ATCO Gas application, Sections 5.1.2-5.1.3, paragraphs 152-153, pages 53-54.
1189 Exhibit 629.01, Calgary argument, Section 18.1, page 71.
1190 Exhibit 110.01, AltaGas application, Section 2.3, paragraph 42, page 11.
1191 Exhibit 110.01, AltaGas application, Section 13.0, paragraph 125, page 40.
1192 Exhibit 634.02, UCA argument, Section 18.1, paragraphs 424-427, pages 75-76.
1193 Exhibit 636.01, CCA argument, Section 18.2, paragraph 385, page 133.
1194 Exhibit 635.01, IPCAA argument, Section 18.1, paragraph 96, page 15.

994. The Commission determines that long-term forecasts of billing determinants as proposed by Fortis and ATCO Electric are not necessary. As identified by Fortis, the use of long-term forecasts introduces forecasting risk into the PBR plan with respect to billing determinants. Because the billing determinants are generally used to allocate items that have been determined to be exceptions to the incentive properties of PBR, the Commission considers that it is necessary to achieve a greater degree of accuracy. The Commission does not consider that the company or its customers should benefit from, or be negatively impacted by, forecasting inaccuracies that may result from using forecasts that extend well into the future. Utilizing a shorter term for the forecasts will reduce the possibility for material forecasting inaccuracies. For this reason the companies will provide a revised forecast of their billing determinants annually as part of the September 10th annual PBR rate adjustment filings. In addition, the companies will provide the billing determinants forecast to be utilized for January 1, 2013 rates as part of their compliance filings to this decision.

995. Companies will be expected to utilize forecasting methodologies that are logical and easy to understand, and in most cases this will involve the continued use of forecasting methodologies utilized prior to PBR. Companies should utilize consistent billing determinant forecasting methodologies during the PBR term unless the Commission orders otherwise. Companies will describe the methodology they plan to use for the duration of the PBR term as part of their compliance filings to this decision.

996. The Commission considers that PBR is unrelated to the requirement to periodically update rates through a Phase II process. However, during the PBR term the companies may file applications for Phase II adjustments to their rate design and cost allocation methodologies and the Commission will make a determination at that time as to whether the adjustments are warranted. For purposes of a cost of service study, the companies shall use the revenue requirement resulting from going-in rates adjusted by the PBR formula (including the I-X mechanism, K factors, Y factors and Z factors) and the latest updated billing determinants.

15.2 AUC Rule 002 and AUC Rule 005 annual filings

997. As discussed in Section 13, annual AUC Rule 005 filings will continue to be filed by the companies on May 1st for electric distribution utilities and May 15th for gas distribution utilities. In addition, a copy of the prior year AUC Rule 005 filings will be included with the September 10th annual PBR rate adjustment filing.

998. As discussed in Section 14.1, the service quality of the companies will continue to be monitored using the AUC Rule 002 process. Annual service quality filing requirements are set out in the provisions of the rule.

15.3 Summary of annual filing dates

999. Below is a summary of the key annual filing dates under the PBR plans.

Table 15-1 Summary of key PBR annual filing requirements

Date	Action
March 1	Submission of capital tracker applications
May 1 or 15	AUC Rule 005 annual filings (May 1 for electric utilities, May 15 for gas utilities)
September 10	Companies to file annual PBR rate adjustment filings
January 1	Effective date for approved rates that are subject to the PBR formula

16 Generic proceedings

1000. During the first PBR term, the Commission will conduct a number of generic proceedings to deal with issues that arose out of the cost of service regulatory regime, some of which are still relevant to the companies under PBR. These proceedings are “generic” because the issues affect more than one company, including issues such as the recognition of debt costs or the treatment of certain income tax expenses. These generic proceedings are intended to make regulation in Alberta, including regulation of those companies that remain under cost of service regulation, more efficient and more predictable.

1001. To the extent that the decisions coming out of these generic proceedings will impact the companies under PBR, prior to the end of the PBR term, the Commission will consider any necessary rate adjustments using the mechanisms set out in Section 15.1.4 of this decision, as matters arise.

1002. The Commission will shortly issue bulletins to commence a proceeding on the generic cost of capital and to either continue Proceeding ID No. 20 with respect to Utility Asset Dispositions or initiate a generic proceeding regarding asset disposition and stranded assets. Additionally, the Commission will initiate other generic proceedings and will seek input from interested parties on additional matters parties may wish to have considered in generic proceedings, the scope of the issues to be considered, and the format for these proceedings. With regard to the latter, the Commission expects that many of these generic proceedings can take the form of consultations.

17 Order

1003. It is hereby ordered that each of AltaGas Utilities Inc., ATCO Electric Ltd., ATCO Gas and Pipelines Ltd., EPCOR Distribution & Transmission Inc. and FortisAlberta Inc. shall file a compliance filing in accordance with the directions set out in this decision by November 2, 2012. The compliance filing shall include proposed distribution rate schedules to be effective January 1, 2013 with supporting documentation including:

- base rates for going-in rates by rate class that will be the starting point for 2013 rates
- I factor calculation as described in Section 15.1.1 with supporting backup
- provision component of the Y factor adjustment to collect Y factors that are not collected through separate riders calculated as described in Section 15.1.4
- billing determinants for each rate class for gas applications
- billing determinants that will be used to allocate Y factor provisions to rate classes
- backup showing the application of the formula by rate class and resulting rate schedules
- any other material relevant to the establishment of current year rates

Dated on September 12, 2012.

The Alberta Utilities Commission

(original signed by)

Willie Grieve, QC
Chair

(original signed by)

Mark Kolesar
Vice-Chair

(original signed by)

Moin A. Yahya
Commission Member

Appendix 1 – Proceeding participants

Name of organization (abbreviation) counsel or representative
ATCO Electric Ltd. (ATCO Electric or AE) L. Keough L. E. Smith L. Kizuk D. Werstiuk J. Teasdale V. Porter M. Bayley
AltaLink Management Ltd. J. Piotto T. Kanasoot E. Tadayoni J. Yeo J. Wrigley K. Evans
ATCO Gas (ATCO Gas or AG) L. E. Smith D. Wilson A. Green M. Bayley L. Fink
ATCO Pipelines L. E. Smith E. Jansen S. Mah D. Dunlop B. Jones A. Jukov
AltaGas Utilities Inc. (AltaGas or AUI) N. J. McKenzie R. Koizumi J. Coleman C. Martin P. E. Schoech
The City of Calgary (Calgary) D. I. Evanchuk G. Matwichuk
Central Alberta Rural Electrification Association D. Evanchuk P. Bourne
Consumers' Coalition of Alberta (CCA) J. A. Wachowich J. A. Jodoin A. P. Merani

Name of organization (abbreviation) **counsel or representative**
Direct Energy Marketing Limited S. Puddicombe
EPCOR Distribution & Transmission Inc. (EPCOR or EDTI) J. Liteplo D. Gerke P. Wong D. Tenney
ENMAX Power Corporation (ENMAX or EPC) D. Emes G. Weismiller K. Hildebrandt J. Schlauch J. Worsick
FortisAlberta Inc. (Fortis or FAI) J. Walsh
Graves Engineering Corporation J. T. Graves
Industrial Gas Consumers Association of Alberta (IGCAA) G. Sproule
Industrial Power Consumers Association of Alberta (IPCAA) M. Forster T. Clarke R. Mikkelsen S. Fulton V. Bellissimo
City of Lethbridge M. Turner O. Lenz
National Economic Research Associates (NERA) J. Cusano L. Aufricht J. Markholm
The City of Red Deer M. Turner L. Gan
South Alta Rural Electrification Association D. Evanchuk B. Bassett

Name of organization (abbreviation) **counsel or representative**
Office of the Utilities Consumer Advocate (UCA) C. R. McCreary S. Mattuli W. Taylor R. Bell

The Alberta Utilities Commission Commission Panel W. Grieve, QC, Chair M. Kolesar, Vice-Chair M. A. Yahya, Commission Member Commission Staff B. McNulty (Commission counsel) C. Wall (Commission counsel) A. Sabo (Commission counsel) J. Thygesen O. Vasetsky B. Miller L. Ou D. Mitchell K. Schultz D. Ward B. Clarke S. Karim P. Howard J. Olsen B. Whyte W. Frost G. Scotton S. L. Levin, Emeritus Professor of Economics Department of Economics and Finance School of Business Southern Illinois University Edwardsville

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Appendix 2 – Oral hearing – registered appearances

Name of organization (abbreviation) counsel or representative	Witnesses
National Economic Research Associates, Inc (NERA) J. Cusano L. Aufricht	J. Makholm A. Ros
AltaGas Utilities Inc. (AltaGas or AUI) N. J. McKenzie	P. Schoech R. Camfield G. Johnston A. Mantei R. Retnanandan
ATCO Electric Ltd. and ATCO Gas (ATCO) L. Smith, QC K. Illsey	P. Carpenter M. Bayley D. Wilson D. Freedman B. Goy J. Cummings N. Palladino
The City of Calgary (Calgary) D. I. Evanchuk E. W. Dixon	G. Matwichuk H. Johnson
Consumers Coalition of Alberta (CCA) J. Wachowich	M. Lowry
EPCOR Distribution & Transmission Inc. (EPCOR or EDTI) J. Liteplo C. Bystrom	Panel 1 (PRB principles and structure) D. Weisman D. Gerke D. Cole J. Elford H. Haag Panel 2 (PBR inflation, productivity and formula issues) D. Ryan D. Gerke J. Baraniecki C. Cicchetti
FortisAlberta Inc. (Fortis or FAI) T. Dalgleish, QC	I. Lorimer P. Delaney M. Stroh J. Frayer
ENMAX Power Corporation (ENMAX or EPC) D. Wood L. Cusano	K. Hildebrandt G. Weismiller R. Lawton

Name of organization (abbreviation) **counsel or representative**	**Witnesses**
Industrial Power Consumers Association of Alberta (IPCAA) M. Forster	R. Cowburn V. Bellissimo R. Mikkelsen
Office of the Utilities Consumer Advocate (UCA) C. R. McCreary N. Parker	F. Cronin S. Motluk R. Bell

The Alberta Utilities Commission Commission Panel W. Grieve, QC, Chair M. Kolesar, Vice-Chair M. A. Yahya, Commission Member Commission Staff B. McNulty (Commission counsel) C. Wall (Commission counsel) A. Sabo (Commission counsel) J. Thygesen O. Vasetsky B. Miller S. L. Levin, Emeritus Professor of Economics Department of Economics and Finance School of Business Southern Illinois University Edwardsville

Appendix 3 – Major procedural steps in rate regulation initiative: performance-based regulation

(return to text)

1. On February 26, 2010, the Commission wrote in a letter (Exhibit 1.01) sent to interested parties that it was "beginning an initiative to reform utility rate regulation in Alberta."

2. The Commission established a roundtable meeting of interested parties, which took place March 25, 2010 in the AUC hearing room in Edmonton. At the roundtable, the distribution companies said they could file PBR proposals by the end of the first quarter of 2011: March 31, 2011.

3. In an April 9, 2010 letter (Exhibit 6.01) to interested parties, the Commission outlined the discussions at the roundtable and notified them it had contracted the Van Horne Institute to organize a PBR workshop May 26 and May 27 in Edmonton.

4. On May 14, 2010, the Commission issued a letter (Exhibit 27.01) to interested parties on the process for development of guiding PBR principles, which the Commission planned to release via AUC bulletin on July 8, 2010. That letter established a process schedule to receive submissions on which specific incentive-based proposals would be evaluated, with initial submissions to be provided by June 10, 2010 and comments on the submissions to be provided by June 17, 2010.

5. The PBR workshop took place in Edmonton on May 26 and May 27, 2010. Material on the legal dimensions and regulatory evolution of PBR were distributed to roundtable participants ahead of the roundtable, on May 20, 2010.

6. On June 15, 2010, AltaGas Utilities Inc. (AltaGas) proposed a one-week extension to the June 17, 2010 deadline. In a letter (Exhibit 53.01) dated June 16, 2010, the Commission agreed to the request and adjusted the date for its PBR bulletin issuance to July 15, 2010.

7. On July 15, 2010, the Commission issued Bulletin 2010-20 (Exhibit 64.01). In that bulletin the Commission stated the five principles that would guide its examination of specific PBR proposals from regulated utilities.

8. In August, 2010, the Commission hired National Economic Research Associates Inc. (NERA) as an independent consultant to conduct a total factor productivity study or studies.

9. In a letter (Exhibit 71.01) to interested parties dated September 8, 2010, the Commission set out the terms of reference for NERA's engagement.

10. In letters (exhibits 76.01 and 78.01) to the Commission dated November 12 and November 25, 2010, respectively, ATCO Gas and ATCO Electric (jointly ATCO), and AltaGas requested extensions to both the previously established date for filing their PBR proposals of March 31, 2011 and the previously established date for implementation of PBR plans of July 1, 2012. Both requested implementation be delayed to January 1, 2013.

11. By correspondence (Exhibit 79.01) to interested parties on December 16, 2010, the Commission agreed to postpone ATCO and AltaGas' PBR plan filing dates to May 31, 2011 and their PBR implementations to January 1, 2013.

12. NERA filed its expert report (Exhibit 80.02) on total factor productivity with the Commission on December 30, 2010.

13. On February 7, 2011, the Consumers Coalition of Alberta (CCA) expressed concerns about the proposed proceeding schedule, including the May 31, 2011 deadline for filing of PBR plans, due to a heavy regulatory agenda (Exhibit 86.02).

14. On March 24, 2011 EPCOR Distribution & Transmission Inc. (EPCOR), AltaGas, FortisAlberta Inc. (Fortis), ATCO Electric and ATCO Gas submitted a joint letter (Exhibit 89.01) to the Commission requesting a further deadline extension.

15. In a letter (Exhibit 90.01) to the parties dated March 29, 2011, the Commission agreed to certain proceeding schedule changes, including proposing the postponement of filing of utility PBR plans to July 22, 2011. In the same letter the Commission proposed a simplified compliance filing process to ensure that PBR plans could be implemented by January 1, 2013.

16. Following responses from parties, the Commission in a letter (Exhibit 94.01) dated April 13, 2011 set a new proceeding schedule, with utility PBR plans to be submitted July 22, 2011 and a hearing scheduled to begin March 5, 2012.

17. On June 1, 2011, the Lieutenant Governor in Council issued an Order in Council, in which it authorizes the Commission:

> (a) to proceed to fix or approve just and reasonable rates, tolls or charges, or schedules of them, that may be charged by ATCO Gas and Pipelines Ltd. or AltaGas Utilities Inc. under section 45 of the Gas Utilities Act
>
> (i) pursuant to an application filed within the period from June 1, 2011 to December 31, 2013 with the Commission by ATCO Gas and Pipelines Ltd. or AltaGas Utilities Inc. pursuant to, or related to the provisions of, section 45 of the Gas Utilities Act, or
>
> (ii) on the Commission's own motion or initiative commenced within the period from June 1, 2011 to December 31, 2013,

and

> (b) to approve any related, ancillary, compliance or subsequent application arising out of an approval granted, or a direction issued, by the Commission pursuant to an application filed under clause (a)(i) or a motion or initiative of the Commission referred to in clause (a)(ii).

18. On July 22, 2011 PBR submissions and applications were filed by each of ATCO Electric, ATCO Gas, Fortis, EPCOR, and AltaGas.

19. Also on July 22, 2011, AltaGas submitted a letter (Exhibit 102.01) to the Commission requesting approval to negotiate its PBR application with its customer groups.

20. On July 26, 2011 the Commission issued a notice of proceeding (Exhibit 105.01), acknowledging the receipt of the PBR applications and soliciting statements of intention to participate (SIPs) from any party not already registered in the proceeding that wished to intervene or participate. The Commission also re-iterated the proceeding schedule it had issued in its letter to parties of April 13, 2011.

21. On August 12, 2011 the Commission wrote to registered parties in regard to AltaGas' request to negotiate a settlement of its PBR application with its customers (Exhibit 112.01). The Commission requested comment from AltaGas on its rationale for the request by August 19, 2011 and comment from other companies and interveners by August 26, 2011. AltaGas was afforded an opportunity to then reply to other companies' and interveners' forthcoming comments by August 30, 2011.

22. On August 25, 2011, the Commission informed proceeding parties by letter (Exhibit 114.01) that it had chosen to expand the role of NERA "to undertake the preparation of a second report to provide parties and the Commission with an independent, expert critical analysis and evaluation of the material aspects of the utility applications and intervener evidence in Proceeding ID No. 566."

23. On August 31, 2011, the Commission began Round 1 of information requests (IRs) related to the proceeding with questions circulated to all of the companies registered as parties and to NERA.

24. On September 30, 2011 in correspondence (Exhibit 181.01) to all parties, the Commission denied AltaGas' request to negotiate a settlement of its PBR application with its customers.

25. On the same day, ATCO Electric filed a letter (Exhibit 182.01) with the Commission objecting to the IRs filed by The City of Calgary (Calgary) directed to ATCO Electric and to Dr. Carpenter relating to the ATCO Electric application.

26. By letter (Exhibit 183.01) dated October 3, 2011, the Commission requested Calgary's comments on the ATCO Electric objection by October 5, 2011 and ATCO Electric's reply by October 6, 2011.

27. In its letter (Exhibit 186.01) to the parties dated October 11, 2011, the Commission allowed the Calgary IRs to stand and directed ATCO Electric and Dr. Carpenter to answer the IRs.

28. On November 9 and November 10, 2011, the Commission received several motions from each of the UCA, Calgary, and the CCA, requesting for full, responsive and adequate answers to certain IRs from the NERA, AltaGas, Fortis, EPCOR, Dr. Carpenter, and ATCO.

29. The Commission established a process by letter (Exhibit 263.01) dated November 10, 2011, to deal with the motions, which requested NERA and each of the companies or their experts to respond to the motions on November 16, 2011, and concluded with reply comments from the UCA, the CCA and Calgary on November 18, 2011.

30. On November 23, 2011, the Commission wrote to registered parties and provided its rulings on each of the individual motion items (Exhibit 282). In the same letter the Commission set a revised proceeding schedule, with intervener evidence to be submitted December 16, 2011 and a hearing scheduled to begin April 16, 2012.

31. On January 16 and 26, 2012, the Commission issued Round 2 and Round 3 of IRs.

32. On February 22, 2012, NERA filed its second report (Exhibit 391.02): *Update, reply and PBR Plan Review for AUC Proceeding 566 – Rate Regulation Initiative*.

33. Also on February 22, 2012, ATCO Electric and ATCO Gas filed updates (exhibits 389 and 390) to their respective PBR applications.

34. In a letter (Exhibit 392.01) to registered parties dated February 24, 2012, the Commission provided for a further evidentiary process to allow for information requests, responses and supplemental intervener evidence with respect to ATCO's application updates.

35. On February 29, 2012, the UCA filed a letter (Exhibit 395.01) objecting to the application update filed by ATCO Gas on various grounds and requesting the Commission to undertake certain steps, including the striking of portions of that evidence from the record of the proceeding.

36. On March 1, 2012, the Commission issued a letter (Exhibit 399.01) indicating that it would treat the UCA letter as a motion requiring a Commission decision following a reply to the ATCO response by the UCA not later than March 5, 2012.

37. On March 7, 2012 in correspondence (Exhibit 416.01) to the parties, the Commission permitted the amendment of the ATCO application updates and denied the UCA motion.

38. Also on March 7, 2012, the Commission began Round 4 of IRs in regard to NERA second report.

39. On March 8, 2012, the Commission issued Round 5 of IRs to ATCO in respect of its application updates.

40. By letter (Exhibit 470.01) dated April 4, 2012, the Commission advised parties of the details of oral hearing scheduled to commence April 16, 2012.

41. On April 12 and 13, 2012, the Commission issued Round 6 and Round 7 of IRs.

42. An oral hearing was held in the Commission's Calgary hearing room from April 16, 2012 to May 8, 2012. At the close of the hearing, the Commission directed parties to submit argument by June 8, 2012, and reply argument by July 6, 2012.

43. On June 5, 2012, multiple parties requested an extension of the deadline for filing argument from June 8, 2012 to June 13, 2012. In a letter (Exhibit 627.01) dated June 7, 2012, the Commission agreed to the request and adjusted the date for filing reply argument to July 11, 2012.

44. On July 6, 2012, ATCO proposed a two-day extension to the July 11, 2012 deadline. By letter (Exhibit 640.01) issued on the same day, the Commission agreed to postpone reply argument filing dates to July 13, 2012 for all parties.

45. On July 13, reply argument was received.

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Appendix 4 – Abbreviations

Abbreviation	Name in full
AESO	Alberta Electric System Operator
AG	ATCO Gas
AHE	average hourly earnings
AltaGas or AUI	AltaGas Utilities Inc.
AMR	automated meter reading
ATCO	ATCO Electric and ATCO Gas
ATCO Electric or AE	ATCO Electric Ltd.
AWE	average weekly earnings
CAIDI	customer average interruption duration index
capex	capital expenditures
Calgary	The City of Calgary
CCA	Consumers' Coalition of Alberta
CPI	consumer price index
CSLS	Center for the Study of Living Standards
DSM	demand side management
ECM	efficiency carry-over mechanism
ENMAX or EPC	ENMAX Power Corporation
EPCOR or EDTI	EPCOR Distribution & Transmission Inc.
ESM	earnings sharing mechanism
EUCPI	electric utility construction price index
FBR	formula-based ratemaking
FERC	Federal Energy Regulatory Commission
Fortis or FAI	FortisAlberta Inc.
G&A	general and administrative expenses
GCOC or GCC	generic cost of capital
GDP-IPI	gross domestic product implicit price index
GDP-IPI-FDD	gross domestic product implicit price index for final domestic demand
G factor	growth factor
GRA	general rate application
GTA	general tariff application
I factor	inflation factor
IPCAA	Industrial Power Consumers Association of Alberta
IR	information request

Abbreviation	Name in full
KFEI	K factor efficiency incentive
kWh	kilowatt hours
LBDA	load balancing deferral account
LDC	local distribution company
MFP	multifactor productivity
MIL	maximum investment levels
MP factor	major projects factor
NAICS	North American Industry Classification System
NERA	National Economic Research Associates Inc.
NGSSC	Natural Gas System Settlement Code
O&M	operating and maintenance
PBR	performance-based regulation
PEG	Pacific Economics Group
PFAM	post-final adjustment mechanism
PFP	partial productivity factor
ROE	return on equity
SAIDI	system average interruption duration index
SAIFI	system average interruption frequency index
SAS	(transmission) system access service
SQR	service quality regulation
TAC	transmission access charge
TFO	transmission facility owner
TFP	total factor productivity
TRIF	total recordable injury frequency rate
UCA	Office of the Utilities Consumer Advocate
UMR	urban mains replacement
USA/MFR	uniform system of accounts/minimum filing requirements
WDA	weather deferral account
X factor	productivity factor
Z factor	exogenous factor

Appendix 5 – Company descriptions

AltaGas Utilities Inc.

AltaGas Utilities Inc. is a Leduc-based provider of natural gas distribution services in more than 90 Alberta communities.[1195]

The company operates 20,000 line km of gas distribution pipelines serving more than 72,000 residential, rural and commercial customers in Alberta and employs 200 people. The company's roots stretch back to 1947 and operations in the Athabasca, St. Paul and Leduc areas. Today the company serves communities that also include Barrhead, Bonneyville, Drumheller, Hanna, Three Hills, Grande Cache, High Level, Morinville, Pincher Creek, Dunmore, Stettler, Two Hills, Elk Point and Westlock.

AltaGas Utilities also offers natural gas service for customers with annual load requirements of more than 20,000 gigajoules anywhere in Alberta, an alternative to communities that have existing natural gas service from another supplier, and provides natural gas service proposals to communities that do not currently have natural gas service.

AltaGas Utilities is a unit of AltaGas Ltd., a Calgary-based energy infrastructure company that among other things also operates natural gas utilities in British Columbia, Nova Scotia and has a one-third interest in a Northwest Territories utility. Together, the natural gas utility firms serve 115,000 customers.

[1195] All information in this summary was derived from company filings and the AltaGas Utilities (http://www.altagasutilities.com/) and AltaGas Ltd. (http://www.altagas.ca/) websites, accessed on August 16, 2012.

ATCO Electric Ltd.

ATCO Electric Ltd. is an Edmonton-based developer and operator of regulated electricity distribution and transmission infrastructure.[1196] In Alberta, the company operates in the northern and east-central regions of the province through 38 offices in its service area, which covers 245 Alberta communities and includes almost 213,000 customers. It has two divisions: capital projects and operations, with capital projects overseeing construction of major transmission projects and operations overseeing construction of large distribution projects and the management and operation of the company's existing transmission, distribution and technology assets.

Along with larger communities such as Grande Prairie, Fort McMurray, Jasper and Lloydminster, ATCO Electric's service area includes many rural and energy-rich areas of the province and covers the northern half of Alberta, an area west and north of Lloydminster and an area east of Calgary. This is about two-thirds of the geographic area of Alberta.

The company is a unit of publicly-listed ATCO Ltd. through ATCO Ltd. affiliates Canadian Utilities Ltd. and CU Inc. ATCO Ltd. is controlled by ATCO Ltd. Chairman Ron Southern through the Southern family holding company, Sentgraf Ltd. Along with its core operations in Alberta, which stretch back 85 years, ATCO Electric also operates in the Canadian north, principally the Yukon and the Northwest Territories, through subsidiaries Yukon Electrical Company Limited, Northland Utilities (NWT) Limited and Northland Utilities (Yellowknife) Limited.

ATCO Electric has an employee count of more than 2,000 people and operates approximately 10,000 km of transmission lines and 62,000 km of distribution lines. The company also operates roughly 10,000 km of distribution lines on behalf of 24 rural electrification associations (REAs) that are within its service territory. In fiscal 2011, the members of six REAs voted to sell their electric system assets to ATCO Electric. In the same year, the company experienced what it described as large-scale growth in transmission development and a similar level of distribution growth related to distribution extension and construction.

Major projects in fiscal 2011 included work on the proposed Eastern Alberta Transmission Line, which is the subject of an application currently before the AUC; the Hanna region transmission development project; and the northeast transmission development projects in the Fort McMurray area. Internally, the company was focused on customer service; operational excellence, talent attraction, development and retention and responding to a changing regulatory environment. The latter work centred around the AUC's Rate Regulation Initiative on Performance-Based Regulation.

[1196] All information in this summary is derived from the ATCO Ltd. 2011 annual report and the ATCO Ltd. (http://www.atco.com/),Canadian Utilities Ltd. (http://www.canadianutilities.com/) and ATCO Electric (http://www.atcoelectric.com/default.asp) websites accessed on August 16, 2012.

ATCO Gas

ATCO Gas is an Edmonton-based distributor of natural gas with more than one million customers in about 300 communities throughout Alberta.[1197] It operates approximately 38,000 km of distribution pipes and employs about 2,000 Albertans at its headquarters and across its province-wide network of more than 60 district offices.

The company is celebrating its 100th anniversary of founding in 2012. The roots of the company go back to the origins of natural gas service in the province of Alberta in 1912 with Canadian Western Natural Gas in southern Alberta and the Calgary area, and Northwestern Utilities Limited in northern Alberta and the Edmonton area in 1923.

Along with natural gas distribution, ATCO Gas provides expert advice to consumers through ATCO EnergySense and the ATCO Blue Flame Kitchen. It is the largest natural gas distribution utility in Alberta and serves municipal, residential, business and industrial customers.

The company is a division of ATCO Gas and Pipelines Ltd., which is in turn part of the publicly-listed ATCO Ltd. corporate group. ATCO Ltd. ATCO Ltd. is controlled by ATCO Ltd. Chairman Ron Southern through the Southern family holding company, Sentgraf Ltd.

In 2011 ATCO Gas spent more than $287 million on capital projects it said enhanced system integrity and reliability and ensured public safety.

[1197] All information in this summary is derived from company filings, the ATCO Ltd. 2011 annual report and the ATCO. Ltd. (http://www.atco.com/) and ATCO Gas (http://www.atcogas.com/) websites, accessed on August 16, 2012.

EPCOR Distribution & Transmission Inc.

EPCOR Distribution and Transmission Inc. (EDTI) provides electricity distribution service through aerial and underground distribution lines and related facilities to its service area in the city of Edmonton.[1198]

The company is a wholly owned subsidiary of EPCOR Utilities Inc., a provider of electricity and water services to customers in Canada and the United States, and is owned by the City of Edmonton. Both EDTI and its corporate parent are based in Edmonton. The parent was founded in October 1891 as the Edmonton Electric Lighting and Power Company and became municipally owned in 1902.

EDTI provides electricity distribution services to more than 308,000 residential and 35,000 commercial consumers in Edmonton, distributing roughly 14 per cent of Alberta's electricity consumption. The company operates 72-kV, 138-kV, 240-kV and 500-kV lines and cables. It distributes electricity in Edmonton through a network of eight distribution substations, 287 distribution feeders and approximately 5,000 circuit km of primary distribution lines.

Along with distribution services, EDTI also operates high-voltage substations and high-voltage transmission lines in the Edmonton area, including 203 circuit km of transmission lines and 29 transmission substations. These form part of the Alberta interconnected electric system. EDTI also provides services to the Alberta Electric System Operator, provides the distribution tariff and settlement services in Edmonton for the competitive electric market. It also manages and collects load data in the Edmonton area through meter reading, data collection and management.

The company employs approximately 629 people in its distribution arm and 139 individuals in its transmission operations.

[1198] All information in this summary is derived from company filings and the EPCOR Utilities Inc. website (http://corp.epcor.com/Pages/home.aspx) accessed on August 16, 2012.

FortisAlberta Inc.

FortisAlberta Inc. distributes electricity to nearly half-a-million Albertans living in 200 communities across central and southern Alberta.[1199]

The company's origins are as the distribution arm of TransAlta Corp., which TransAlta sold in 2000, and it operates 115,000 km of power lines across a 225,000-km service area that represents more than 60 per cent of Alberta's low-voltage distribution network.

Based in Calgary, FortisAlberta employs 1,000 people working at its headquarters and 52 service points in its service territory. The company operates a 24-hour outage repair and emergency response capability, builds, maintains and upgrades power lines and facilities, installs and reads electricity meters, provides consumption data to retailers that bill customers and promotes electrical safety in the communities it serves.

FortisAlberta is a subsidiary of publicly-listed Fortis Inc., Canada's largest investor-owned distribution utility and which among other things operates regulated electric utilities in five Canadian provinces and a natural gas utility in British Columbia. Fortis Inc. is based in St. John's, Newfoundland and Labrador and its shares trade on the Toronto Stock Exchange.

[1199] All information in this summary was derived from company filings, AUC records, and the FortisAlberta Inc. (http://www.fortisalberta.com/home.aspx) and Fortis Inc. (http://www.fortisinc.com/) websites, accessed on August 16, 2012.

OEB Distribution System Code

Ontario

ONTARIO ENERGY BOARD

Distribution System Code

Last revised on October 1, 2011
(Originally Issued on July 14, 2000)

Distribution System Code

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1 GENERAL AND ADMINISTRATIVE PROVISIONS

1.1 The Purpose of this Code

This Code sets the minimum conditions that a distributor must meet in carrying out its obligations to distribute electricity under its licence and the *Energy Competition Act, 1998*. Unless otherwise stated in the licence or Code, these conditions apply to all transactions and interactions between a distributor and all retailers, generators, distributors, transmitters and consumers of electricity who use the distributor's distribution system.

1.2 Definitions

In this Code:

"Accounting Procedures Handbook" means the handbook approved by the Board and in effect at the relevant time, which specifies the accounting records, accounting principles and accounting separation standards to be followed by the distributor;

"Act" means the Ontario Energy Board Act, 1998, S.O. 1998, C. 15, Schedule B;

"Affiliate Relationships Code" means the code, approved by the Board and in effect at the relevant time, which among other things, establishes the standards and conditions for the interaction between electricity distributors or transmitters and their respective affiliated companies;

"ancillary services" means services necessary to maintain the reliability of the IESO-controlled grid; including frequency control, voltage control, reactive power and operating reserve services;

"bandwidth" means a distributor's defined tolerance used to flag data for further scrutiny at the stage in the VEE process where a current reading is compared to a reading from an equivalent historical billing period. For example, a 30 percent bandwidth means a current reading that is either 30 percent lower or 30 percent higher than the measurement from an equivalent historical billing period will be identified by the VEE process as requiring further scrutiny and verification;

"Board" means the Ontario Energy Board;

"capacity allocation exempt small embedded generation facility" means an embedded generation facility which is not a micro-embedded generation facility and which has a name-plate rated capacity of 250 kW or less in the case of a facility connected to a less than 15 kV line and 500 kW or less in the case of a facility connected to a 15 kV or greater line;

"Code" means the Distribution System Code;

"competitive retailer" is a person who retails electricity to consumers who do not take Standard Supply Service ("SSS");

"complex metering installation" means a metering installation where instrument transformers, test blocks, recorders, pulse duplicators and multiple meters may be employed;

"Conditions of Service" means the document developed by a distributor in accordance with subsection 2.4 of this Code that describes the operating practices and connection rules for the distributor;

"connection" means the process of installing and activating connection assets in order to distribute electricity;

"Connection Agreement" means an agreement entered into between a distributor and a person connected to its distribution system that delineates the conditions of the connection and delivery of electricity to or from that connection;

"connection assets" means that portion of the distribution system used to connect a customer to the existing main distribution system, and consists of the assets between the point of connection on a distributor's main distribution system and the ownership demarcation point with that customer;

"connection cost agreement" means the agreement referred to in section 6.2.18;

"consumer" means a person who uses, for the person's own consumption, electricity that the person did not generate;

"customer" means a person that has contracted for or intends to contract for connection of a building or an embedded generation facility. This includes developers of residential or commercial sub-divisions;

“demand meter” means a meter that measures a consumer’s peak usage during a specified period of time;

“disconnection” means a deactivation of connection assets that results in cessation of distribution services to a consumer;

"disconnect/collect trip" is a visit to a customer's premises by an employee or agent of the distributor to demand payment of an outstanding amount or to shut off or limit distribution of electricity to the customer failing payment;

“distribute”, with respect to electricity, means to convey electricity at voltages of 50 kilovolts or less;

“distribution losses” means energy losses that result from the interaction of intrinsic characteristics of the distribution network such as electrical resistance with network voltages and current flows;

“distribution loss factor” has the meaning described to it in the Retail Settlement Code;

“distribution services” means services related to the distribution of electricity and the services the Board has required distributors to carry out;

“distribution system” means a system for distributing electricity, and includes any structures, equipment or other things used for that purpose. A distribution system is comprised of the main system capable of distributing electricity to many customers and the connection assets used to connect a customer to the main distribution system;

“Distribution System Code” means the code, approved by the Board, and in effect at the relevant time, which, among other things, establishes the obligations of a distributor with respect to the services and terms of service to be offered to customers and retailers and provides minimum technical operating standards of distribution systems;

“distributor” means a person who owns or operates a distribution system;

“*Electricity Act*” means the *Electricity Act, 1998*, S.O. 1998, c.15, Schedule A;

“Electrical Safety Authority” or “ESA” means the person or body designated under the *Electricity Act* regulations as the Electrical Safety Authority;

“eligible low-income customer” means:

(a) a residential electricity customer who has a pre-tax household income at or below the pre-tax Low Income Cut-Off, according to Statistics Canada, plus 15%, taking into account family size and community size, as qualified by a Social Service Agency or Government Agency; or

(b) a residential electricity customer who has been qualified for Emergency Financial Assistance;

"embedded distributor" means a distributor who is not a wholesale market participant and that is provided electricity by a host distributor;

"embedded generation facility" means a generation facility which is not directly connected to the IESO-controlled grid but instead is connected to a distribution system, and has the extended meaning given to it in section 1.9;

"embedded retail generator" means a customer that:

(a) is not a wholesale market participant or a net metered generator (as defined in section 6.7.1);
(b) owns or operates an embedded generation facility, other than an emergency backup generation facility; and
(c) sells output from the embedded generation facility to the Ontario Power Authority under contract or to a distributor;

"embedded wholesale consumer" means a consumer who is a wholesale market participant whose facility is not directly connected to the IESO-controlled grid but is connected to a distribution system;

"emergency" means any abnormal system condition that requires remedial action to prevent or limit loss of a distribution system or supply of electricity that could adversely affect the reliability of the electricity system;

"emergency backup generation facility" means a generation facility that has a transfer switch that isolates it from a distribution system;

"Emergency Financial Assistance" means any Board-approved emergency financial assistance program made available by a distributor to eligible low-income residential customers;

"*Energy Competition Act*" means the *Energy Competition Act, 1998*, S.O. 1998, c. 15;

"enhancement" means a modification to the main distribution system that is made to improve system operating characteristics such as reliability or power quality or to relieve system capacity constraints resulting, for example, from general load growth, but does not include a renewable enabling improvement;

"exempt distributor" means a distributor as defined in section 3 of the Act who is exempted from various requirements in the Act by Ontario Regulation 161/99;

“expansion” means a modification or addition to the main distribution system in response to one or more requests for one or more additional customer connections that otherwise could not be made, for example, by increasing the length of the main distribution system, and includes the modifications or additions to the main distribution system identified in section 3.2.30 but in respect of a renewable energy generation facility excludes a renewable enabling improvement;

“four-quadrant interval meter” means an interval meter that records power injected into a distribution system and the amount of electricity consumed by the customer;

“generate”, with respect to electricity, means to produce electricity or provide ancillary services, other than ancillary services provided by a transmitter or distributor through the operation of a transmission or distribution system;

“generation facility” means a facility for generating electricity or providing ancillary services, other than ancillary services provided by a transmitter or distributor through the operation of a transmission or distribution system, and includes any structures, equipment or other things used for that purpose;

“generator” means a person who owns or operates a generation facility;

“geographic distributor,” with respect to a load transfer, means the distributor that is licensed to service a load transfer customer and is responsible for connecting and billing the load transfer customer;

“good utility practice” means any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry in North America during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgement in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good practices, reliability, safety and expedition. Good utility practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in North America;

“holiday” means a Saturday, Sunday, statutory holiday, or any day as defined in the Province of Ontario as a legal holiday;

“host distributor” means the distributor who provides electricity to an embedded distributor;

“IESO” means the Independent Electricity System Operator continued under the *Electricity Act.*

"IESO-controlled grid" means the transmission systems with respect to which, pursuant to agreements, the IESO has the authority to direct operations;

"interval meter" means a meter that measures and records electricity use on an hourly or sub-hourly basis;

"large embedded generation facility" means an embedded generation facility with a name-plate rated capacity of more than 10 MW;

"load control device" means a load limiter, timed load interrupter or similar device that limits or interrupts normal electricity service;

"load displacement" means, in relation to a generation facility that is connected on the customer side of a connection point, that the output of the generation facility is used or intended to be used exclusively for the customer's own consumption;

"load limiter device" means a device that will allow a customer to run a small number of electrical items in his or her premises at any given time, and if the customer exceeds the limit of the load limiter, then the device will interrupt the power until it is reset;

"load transfer" means a network supply point of one distributor that is supplied through the distribution network of another distributor and where this supply point is not considered a wholesale supply or bulk sale point;

"load transfer customer" means a customer that is provided distribution services through a load transfer;

"Market Rules" means the rules made under section 32 of the *Electricity Act*;

"master consumer" means the exempt distributor or the person authorized by Ontario Regulation 389/10 to retain a unit smart meter provider for the prescribed property being served by the licensed distributor;

"Measurement Canada" means the Special Operating Agency established in August 1996 by the *Electricity and Gas Inspection Act*, 1980-81-82-83, c. 87, and Electricity and Gas Inspection Regulations (SOR/86-131);

"meter service provider" means any entity that performs metering services on behalf of a distributor or generator;

"meter installation" means the meter and, if so equipped, the instrument transformers, wiring, test links, fuses, lamps, loss of potential alarms, meters, data recorders, telecommunication equipment and spin-off data facilities installed to measure power past a meter point, provide remote access to the metered data and monitor the condition of the installed equipment;

“metering services” means installation, testing, reading and maintenance of meters;

“micro-embedded generation facility” means an embedded generation facility with a name-plate rated capacity of 10 kW or less;

“mid-sized embedded generation facility” means an embedded generation facility with a name-plate rated capacity of 10 MW or less and:

(a) more than 500 kW in the case of a facility connected to a less than 15 kV line; and

(b) more than 1 MW in the case of a facility connected to a 15 kV or greater line;

“MIST meter” means an interval meter from which data is obtained and validated within a designated settlement timeframe. MIST refers to “Metering Inside the Settlement Timeframe”;

“MOST meter” means an interval meter from which data is only available outside of the designated settlement timeframe. MOST refers to “Metering Outside the Settlement Timeframe”;

“Ontario Electrical Safety Code” means the code adopted by O. Reg. 164/99 as the Electrical Safety Code;

“*Ontario Energy Board Act*” means the *Ontario Energy Board Act, 1998*, S.O. 1998, c.15, Schedule B;

“operational demarcation point” means the physical location at which a distributor’s responsibility for operational control of distribution equipment including connection assets ends at the customer;

“ownership demarcation point” means the physical location at which a distributor’s ownership of distribution equipment including connection assets ends at the customer;

“performance standards” means the performance targets for the distribution and connection activities of the distributor as established by the Board pursuant to the Act and in the Rate Handbook;

“physical distributor”, with respect to a load transfer, means the distributor that provides physical delivery of electricity to a load transfer customer, but is not responsible for connecting and billing the load transfer customer directly;

“point of supply”, with respect to an embedded generation facility, means the connection point where electricity produced by the generation facility is injected into the distribution system;

"prescribed property" means one of the properties or classes of property prescribed by Ontario Regulation 389/10;

"rate" means any rate, charge or other consideration, and includes a penalty for late payment;

"Rate Handbook" means the document approved by the Board that outlines the regulatory mechanisms that will be applied in the setting of distributor rates;

"Regulations" means the regulations made under the *Act* or the *Electricity Act*;

"renewable enabling improvement" means a modification or addition to the main distribution system identified in section 3.3.2 that is made to enable the main distribution system to accommodate generation from renewable energy generation facilities;

"renewable energy expansion cost cap" means, in relation to a renewable energy generation facility, the dollar amount determined by multiplying the total name-plate rated capacity of the renewable energy generation facility referred to in section 6.2.9(a) (in MW) by $90,000, reduced where applicable in accordance with section 3.2.27A or section 3.2.27B;

"renewable energy generation facility" has the meaning given to it in the Act;

"renewable energy source" has the meaning given to it in the Act;

"retail", with respect to electricity means,

a) to sell or offer to sell electricity to a consumer
b) to act as agent or broker for a retailer with respect to the sale or offering for sale of electricity, or
c) to act or offer to act as an agent or broker for a consumer with respect to the sale or offering for sale of electricity;

"Retail Settlement Code" means the code approved by the Board and in effect at the relevant time, which, among other things, establishes a distributor's obligations and responsibilities associated with financial settlement among retailers and customers and provides for tracking and facilitating customer transfers among competitive retailers;

"retailer" means a person who retails electricity;

"service area", with respect to a distributor, means the area in which the distributor is authorized by its license to distribute electricity;

"small embedded generation facility" means an embedded generation facility which is not a micro-embedded generation facility with a name-plate rated capacity of 500 kW or less in the case of a facility connected to a less than 15 kV line and 1MW or less in the case of a facility connected to a 15 kV or greater line;

"smart meter" means a meter that is part of an advanced metering infrastructure that meets the functional specification referenced in the Criteria and Requirements for Meters and Metering Equipment, Systems and Technology Regulation, O. Reg. 425/06;

"total losses" means the sum of distribution losses and unaccounted for energy;

"Social Service Agency or Government Agency" means:

(a) a social service agency or government agency that partners with a given distributor to assess eligibility for Emergency Financial Assistance; or
(b) a social service agency or government agency that assesses eligibility for other energy financial assistance or low-income financial assistance programs, and partners with a given distributor to qualify customers for eligibility under this Code;

"timed load interrupter device" means a device that will completely interrupt the customer's electricity intermittently for periods of time and allows full load capacity outside of the time periods that the electricity is interrupted;

"transmission system" means a system for transmitting electricity, and includes any structures, equipment or other things used for that purpose;

"Transmission System Code" means the code, approved by the Board, that is in force at the relevant time, which regulates the financial and information obligations of the Transmitter with respect to its relationship with customers, as well as establishing the standards for connection of customers to, and expansion of a transmission system;

"transmit", with respect to electricity, means to convey electricity at voltages of more than 50 kilovolts;

"transmitter" means a person who owns or operates a transmission system;

"unaccounted for energy" means all energy losses that cannot be attributed to distribution losses. These include measurement error, errors in estimates of distribution losses and unmetered loads, energy theft and non-attributable billing errors;

"unit smart meter" has the meaning ascribed to it in the *Energy Consumer Protection Act, 2010*;

"unit smart meter provider" has the meaning ascribed to it in the *Energy Consumer Protection Act, 2010*;

"unmetered loads" means electricity consumption that is not metered and is billed based on estimated usage;

"validating, estimating and editing" or "VEE" means the process used to validate, estimate and edit raw metering data to produce final metering data or to replicate missing metering data for settlement purposes;

"wholesale buyer" means a person that purchases electricity or ancillary services in the IESO-administered markets or directly from a generator;

"wholesale market participant", means a person that sells or purchases electricity or ancillary services through the IESO-administered markets; and

"wholesale supplier" means a person who sells electricity or ancillary services through the IESO-administered markets or directly to another person, other than a consumer.

1.3 Interpretations

1.3.1 Unless otherwise defined in this Code, words and phrases shall have the meaning ascribed to them in the Act, or the *Electricity Act*, as the case may be. Headings are for convenience only and shall not affect the interpretation of this Code. Words importing the singular include the plural and vice versa. A reference to a document or a provision of a document includes any amendment or supplement to, or any replacement of, that document or that provision of that document. An event that is required under this Code to occur on or by a stipulated day which is a holiday may occur on or by the next day, that is not holiday.

1.3.2 For the purposes of the definition of "eligible low-income customer" in section 1.2 of this Code, a residential electricity customer who has been qualified as an eligible low-income customer shall remain an eligible low-income customer for a period of 2 years from the date on which he or she was so qualified.

1.3.3 A customer shall be treated as an eligible low-income customer for the purposes of this Code once the customer has been qualified as an eligible low-income customer according to the definition in section 1.2 of this Code or has identified himself or herself as provided under section 1.3.2 of this Code.

1.4 To Whom this Code Applies

This Code applies to all electricity distributors licensed by the Ontario Energy Board under Part V of the *Ontario Energy Board Act, 1998*. These entities are obligated to comply with the Code as a condition of their licence.

1.5 Hierarchy of Codes

The order of hierarchy for the Distribution System Code in relation to other codes, subject to any specific conditions of a licence that apply to the distributor, are as follows:

1. Affiliate Relationships Code
2. Distribution System Code
3. Retail Settlement Code
4. Standard Supply Service Code

1.6 Amendments to this Code

This Code may be amended only in accordance with the procedures set out by the Board in the licence issued to a distributor.

1.7 Coming into Force

This Code comes into force on the day subsection 26(1) of the *Electricity Act* comes into force with the following exception.

Any amendments to this Code shall come into force on the date the Board publishes the amendments by placing them on the Board's website after they have been made by the Board, except where expressly provided otherwise.

All of Chapter 3, *Connections and Expansions* and Subsection 6.2.3 of Section 6.2, *Responsibilities to Generators* come into force on September 29, 2000. These provisions do not apply to projects that are the subject of an agreement entered into before November 1, 2000.

The amendments to this Code made by the Board on December 19, 2003 come into effect on March 22, 2004. [Note: Primarily section 6.2. Appendix E and F were also replaced.]

Sections 2.4.6.1, 2.4.6.2 and 2.4.9 to 2.4.28 come into force on the day that is 6 months after these sections are published on the Board's website after having been made by the Board. [Note: These sections were published on February 3, 2004.]

The amendments to this Code made by the Board February 24, 2005 will come into effect 90 days after this date.

Distribution System Code

Section 6.7 of the Code and the amendment to section 4.2 of the “Micro-Embedded Generation Facility Connection Agreement” in Appendix F of the Code, made by the Board on February 1, 2006 come into force on February 10, 2006.

Sections 2.4.30 and 2.4.31 of the Code, made by the Board on May 12, 2006, come into force on the day that is ninety days after they are published on the Board’s website after having been made by the Board. [Note: These sections were published on May 12, 2006.]

The amendments to this Code made by the Board on July 27, 2006, will come into effect 180 days after that date. The amendments will only apply to expansions where the distributor's initial offer to connect the customer and build the expansion, as set out in sections 3.2.8 and 3.2.9, occurs on or after the date the amendments come into force.

All of section 7, Service Quality Requirements, comes into force on January 1, 2009 with the exception of section 7.10.

Section 2.5.6 comes into force on January 1, 2010.

Section 4.7 and Appendix H come into force on the day that is 90 days from the date on which they are published on the Board’s website after having been made by the Board. [Note: Section 4.7 and Appendix H were published on the Board’s website on June 16, 2009.]

The amendments to sections 2.7.1 to 2.7.5, and 4.2.2.6 and 4.2.2.7, come into force on October 1, 2010.

The amendments to sections 2.4.10, 2.4.17, 2.4.20A, 2.4.22A, 2.4.23A, 2.4.25A, 2.4.26A, 2.4.26B, 2.6.1 to 2.6.7, 4.2.2 to 4.2.2.5, 4.2.3, 4.2.5 and 7.10.1 to 7.10.2 come into force on January 1, 2011.

The amendments to sections 1.2 (namely the addition of the definitions for “exempt distributor”, “master consumer”, “prescribed property”, “unit smart meter”, and “unit smart metering”), 5.1.7, 5.1.9, and 5.3.13, made by the Board on December 16, 2010, come into force on January 1, 2011.

The further revisions to sections 1.2 (definition of “Conditions of Service”), 2.4.10, 2.6.6.3(b), 4.2.2 and 4.2.2.1 come into force on February 7, 2011.

The amendments to sections 2.7, 2.8.1 to 2.8.5, and 6.1.2, come into force on April 1, 2011.

The amendment to section 2.9.2 comes into force on April 1, 2011.

The amendments to sections 2.6.6.2A, 2.6.6.2B, 2.6.6.3(c), 2.7.4, 2.7.4.4, 2.7.7, 4.2.2(k) and 4.2.2.4(f) come into force on April 1, 2011.

The amendments to sections 2.7.1A, 2.7.8, 3.1.1(g), 4.2.2.6, 4.2.2.7, 4.2.6 and 7.10(1)(b) come into force on April 1, 2011.

The amendments to sections 1.2 (definitions of “load limiter device”, “timed load interrupter device” and “load control device”), 2.9 and 4.2.2(k2) come into force on July 1, 2011.

The amendments to sections 1.2 (definitions of “eligible low-income customer”, “Emergency Financial Assistance” and “Social Service Agency or Government Agency”), 1.3.1, 1.3.2, 1.3.3, 2.4.11(c), 2.4.11.1, 2.4.11.2, 2.4.23B, 2.4.23C, 2.7.1.3, 2.7.2(c) to (e), 2.7.4.3, 2.7.5.1, 2.7.6, 2.7.6A, 2.9.2, 4.2.2(k1) and 4.2.2.4(f1) come into force on October 1, 2011.

1.8 Requirements for Board Approvals

Any matter under this Code requiring a determination of the Board may be determined by the Board without a hearing or through an oral, written or electronic hearing, at the Board’s discretion.

1.9 Extended Meaning of Embedded Generation Facility

A distributor shall, for all purposes under this Code, treat a generation facility that is connected on the customer side of a connection point to the distribution system as an embedded generation facility. To that end:

a. the terms “connect”, “connected” and “connection” when used in relation to such a generation facility shall be interpreted accordingly; and
b. the distributor shall treat the owner or operator of the generation facility as a generator in relation to the connection and operation of that generation facility.

1.10 Separate Accounts for Embedded Retail Generators

Where an embedded retail generator that has a contract issued under the feed-in-tariff program referred to in section 25.35 of the *Electricity Act* is connected on the customer side of a connection point (as set out in section 1.9), the distributor shall open a separate account for the embedded retail generator and shall for settlement purposes treat the embedded retail generator as a separate customer, separate and apart from any associated load customer. This rule applies regardless of the electrical configuration of the load and generation meters and regardless of whether the embedded retail generator and the associate load customer are the same person or entity.

2 STANDARDS OF BUSINESS PRACTICE AND CONDUCT

2.1 Distributor-owned Generation Facilities

Except as otherwise expressly provided in its licence or this Code, a distributor shall not, in respect of any matter addressed in or under this Code, provide favoured treatment or preferential access to the distributor's distribution system or the distributor's services for any generation facilities whether owned by the distributor, an affiliate or another third party.

2.2 Liability

2.2.1 A distributor shall only be liable to a customer and a customer shall only be liable to a distributor for any damages which arise directly out of the willful misconduct or negligence:

1. Of the distributor in providing distribution services to the customer;
2. Of the customer in being connected to the distributor's distribution system; or
3. Of the distributor or customer in meeting their respective obligations under this Code, their licences and any other applicable law.

2.2.2 Despite section 2.2.1; neither the distributor nor the customer shall be liable under any circumstances whatsoever for any loss of profits or revenues, business interruption losses, loss of contract or loss of goodwill, or for any indirect, consequential, incidental or special damages, including but not limited to punitive or exemplary damages, whether any of the said liability, loss or damages arise in contract, tort or otherwise.

2.3 Force Majeure

2.3.1 Neither party shall be held to have committed an event of default in respect of any obligation under this Code if prevented from performing that obligation, in whole or in part, because of a force majeure event.

2.3.2 If a force majeure event prevents a party from performing any of its obligations under this Code and the applicable Connection Agreement, that party shall:

1. Promptly notify the other party of the force majeure event and its assessment in good faith of the effect that the event will have on its ability to perform any of its obligations. If the immediate notice is not in writing, it shall be confirmed in writing as soon as reasonably practicable.
2. Not be entitled to suspend performance of any of its obligations under this Code to any greater extent or for any longer time than the force majeure event requires it to do;
3. Use its best efforts to mitigate the effects of the force majeure event, remedy its inability to perform, and resume full performance of its obligations;
4. Keep the other party continually informed of its efforts; and
5. Provide written notice to the other party when it resumes performance of any obligations affected by the force majeure event.

2.3.3 Notwithstanding any of the foregoing, settlement of any strike, lockout, or labor dispute constituting a force majeure event shall be within the sole discretion of the party to the agreement involved in the strike, lockout, or labour dispute. The requirement that a party must use its best efforts to remedy the cause of the force majeure event, mitigate its effects, and resume full performance under this Code shall not apply to strikes, lockouts, or labour disputes

2.4 Conditions of Service

2.4.1 A distributor shall document its Conditions of Service that describe the operating practices and connection policies of the distributor. All distributors shall have a Conditions of Service. Subject to this Code and other applicable laws, a distributor shall comply with its Conditions of Service but may waive a provision of its Conditions of Service in favour of a customer or potential customer.

2.4.2 A distributor shall file a copy of its Conditions of Service with the Board, make its Conditions of Service publicly available and provide a copy to any person requesting it. A distributor shall provide one copy per revision for each person that requests it.

2.4.3 A distributor’s existing Conditions of Service will be deemed to meet the standards set out in this Code for a period of one year following the coming into force of this Code, after which point the distributor must comply.

2.4.4 Note: Section 2.4.4 revoked by amendment, effective March 22, 2004.

2.4.5 A distributor's Conditions of Service may be subject to review as part of the distributor's performance based rates plan.

2.4.6 A distributor's Conditions of Service shall include, at a minimum, a description of the following:

- The types of connection service performed by the distributor for each customer class, and the conditions under which these connections will be performed (connection policy).
- The distributor's basic connection service that is recovered through its revenue requirements and does not require a variable connection charge.
- The distributor's capital contribution policy by customer class for an offer to connect, including procedures for collection of capital contributions.
- The demarcation point at which the distributor's operational responsibilities for distribution equipment end at the customer.
- The demarcation point at which the distributor's ownership of distribution equipment ends at the customer.
- The billing cycle period and payment requirements by customer class.-
- Design requirements for connection to the distribution system.
- Voltages at which the distributor provides electricity and corresponding load thresholds.
- Type of meters provided by the distributor.
- Meters required by customer class.
- Quality of Service standards to which the distribution system is designed and operated.
- Conditions under which supply may be unreliable or intermittent.
- Conditions under which service may be interrupted.
- Conditions under which the distributor may disconnect a consumer.
- Policies for planned interruptions.
- The business process the distributor uses to disconnect and reconnect consumers, including means of notification and timing.
- The distributor's rights and obligations with respect to a customer.
- Rights and obligations a consumer or embedded generator has with respect to the distributor.

- The distributor's liability limitations in accordance with this Code.
- The distributor's dispute resolution procedure.
- Terms and conditions under which the distributor provides other services in its capacity as a distributor.

The conditions of service must be consistent with the provisions of this Code and all other applicable codes and legislation including the Rate Handbook.

2.4.6.1 A distributor's Conditions of Service shall include the distributor's security deposit policy which shall be consistent with the provisions of this Code. A distributor's security deposit policy shall include at a minimum the following:

- a list of all potential types/forms of security accepted;
- a detailed description of how the amount of security is calculated;
- limits on amount of security required;
- the planned frequency, process and timing for updating security;
- criteria customers must meet to have security deposit waived and/or returned; and
- methods of enforcement where a security deposit is not paid.

2.4.6.2 In managing customer non-payment risk, a distributor shall not discriminate among customers with similar risk profiles or risk related factors except where expressly permitted under this Code.

2.4.7 If a distributor's Conditions of Service are documented in a form or in an order different than that specified in the generic Conditions of Service attached to this Code as Appendix A, the distributor shall provide a mapping of terms in its Conditions of Service to the sections and subsections in Appendix A.

2.4.8 A distributor shall provide advance public notice of any changes to its Conditions of Service. Notice shall be, at a minimum, provided to each customer by means of a note on and/or included with the customer's bill. The public notice shall include a proposed timeline for implementation of the new Conditions of Service and a means by which public comment may be provided. A distributor shall provide the Board with a copy of the new Conditions of Service once they are implemented. The copy of the revised document shall include a cover letter that outlines the changes from the prior document, as well as a summary of any public comments on the changes.

2.4.9 A distributor may require a security deposit from a customer who is not billed by a competitive retailer under retailer-consolidated billing unless the customer has a good payment history of 1 year in the case of a residential customer, 5 years in the case of a non-residential customer in a <50 kW demand rate class or 7 years in the case of a non-residential customer in any other rate class. The time period that makes up the good payment history must be the most recent period of time and some of the time period must have occurred in the previous 24 months. A distributor shall provide a customer with the specific reasons for requiring a security deposit from the customer.

2.4.10 For the purposes of section 2.4.9, a customer is deemed to have a good payment history unless, during the relevant time period set out in section 2.4.9, the customer has received more than one disconnection notice from the distributor, more than one cheque given to the distributor by the customer has been returned for insufficient funds, more than one pre-authorized payment to the distributor has been returned for insufficient funds, a disconnect / collect trip has occurred or the distributor had to apply a security deposit in accordance with section 2.4.26A and required the customer to repay the security deposit in accordance with section 2.4.26B. If any of the preceding events occur due to an error by the distributor, the customer's good payment history shall not be affected.

2.4.11 Despite section 2.4.9, a distributor shall not require a security deposit where:

(a) a customer provides a letter from another distributor or gas distributor in Canada confirming a good payment history with that distributor for the most recent relevant time period set out in section 2.4.9 where some of the time period which makes up the good payment history has occurred in the previous 24 months;

(b) a customer, other than a customer in a >5000 kW demand rate class, provides a satisfactory credit check made at the customer's expense; or

(c) a customer has been qualified as an eligible low-income customer and requests a waiver under section 2.4.11.1.

2.4.11.1 When issuing a bill for a security deposit in accordance with section 2.4.9, the distributor shall advise a residential customer that the security deposit requirement will be waived for an eligible low-income customer provided that such a customer contacts the distributor and thereafter confirms his or her low-income eligibility. The distributor shall notify the customer by means of a bill insert, bill message, letter or outgoing telephone message and shall include the distributor's contact information where the customer can obtain further information and a referral to a Social Service Agency or Government Agency to review the customer's low-income eligibility.

2.4.11.2 Where a distributor is advised by a Social Service Agency or a Government Agency that the agency is assessing the customer for eligibility as a low-income customer, the due date for payment of the security deposit shall be extended for at least 21 days pending the eligibility decision of the Social Service Agency or Government Agency.

2.4.12 The maximum amount of a security deposit which a distributor may require a customer to pay shall be calculated in the following manner:

billing cycle factor x estimated bill based on the customer's average monthly load with the distributor during the most recent 12 consecutive months within the past two years

Where relevant usage information is not available for the customer for 12 consecutive months within the past two years or where the distributor does not have systems capable of making the above calculation, the customer's average monthly load shall be based on a reasonable estimate made by the distributor.

2.4.13 Despite section 2.4.12, where a non-residential customer in any rate class other than a < 50 kW demand rate class has a credit rating from a recognized credit rating agency, the maximum amount of a security deposit which the distributor may require the non-residential customer to pay shall be reduced in accordance with the following table:

Credit Rating *(Using Standard and Poor's Rating Terminology)*	**Allowable Reduction in Security Deposit**
AAA- and above or equivalent	**100%**
AA-, AA, AA+ or equivalent	**95%**
A-,From A, A+ to below AA or equivalent	**85%**
BBB-,From BBB, BBB+ to below A or equivalent	**75%**
Below BBB- or equivalent	**0%**

2.4.14 For the purposes of calculating the estimated bill under section 2.4.12 for a low-volume consumer or designated consumer who is billed under SSS or distributor-consolidated billing, the price estimate used in calculating competitive electricity costs shall be the same as the price used by the IESO for the purpose of determining maximum net exposures and prudential support obligations for distributors, low-volume consumers and designated consumers. For the purpose of calculating the estimated bill under section 2.4.12 for all other customers billed under SSS or distributor-consolidated billing, the price estimate used in calculating competitive electricity costs shall be the same as the price used by the IESO for the purpose of determining maximum net exposures and prudential support obligations for market participants other than distributors, low-volume consumers and designated consumers.

2.4.15 Subject to section 2.4.6.2, a distributor may in its discretion reduce the amount of a security deposit which it requires a customer to pay for any reason including where the customer pays under an interim payment arrangement and where the customer makes pre-authorized payments.

2.4.16 For the purposes of sections 2.4.12, the billing cycle factor is 2.5 if the customer is billed monthly, 1.75 if the customer is billed bi-monthly and 1.5 if the customer is billed quarterly.

2.4.17 Where a customer, other than a residential electricity customer, has a payment history which discloses more than one disconnection notice in a relevant 12 month period, the distributor may use that customer's highest actual or estimated monthly load for the most recent 12 consecutive months within the past 2 years for the purposes of making the calculation of the maximum amount of security deposit under section 2.4.12.

2.4.18 The form of payment of a security deposit for a residential customer shall be cash or cheque at the discretion of the customer or such other form as is acceptable to the distributor.

2.4.19 The form of payment of a security deposit for a non-residential customer shall be cash, cheque or an automatically renewing, irrevocable letter of credit from a bank as defined in the *Bank Act*, 1991, c.46 at the discretion of the customer. The distributor may also accept other forms of security such as surety bonds and third party guarantees.

2.4.20 A distributor shall permit the customer to provide a security deposit in equal instalments paid over at least four months. A customer may, in its discretion, choose to pay the security deposit over a shorter time period.

2.4.20A Despite section 2.4.20, a distributor shall permit a residential customer to provide a security deposit in equal instalments paid over a period of at least 6 months, including where a new security deposit is required due to the distributor having applied the existing security deposit against amounts owing under section 2.4.26A. A customer may elect to pay the security deposit over a shorter period of time.

2.4.21 Interest shall accrue monthly on security deposits made by way of cash or cheque commencing on receipt of the total deposit required by the distributor. The interest rate shall be at the Prime Business Rate as published on the Bank of Canada website less 2 percent, updated quarterly. The interest accrued shall be paid out at least once every 12 months or on return or application of the security deposit or closure of the account, whichever comes first, and may be paid by crediting the account of the customer or otherwise.

2.4.22 A distributor shall review every customer's security deposit at least once in a calendar year to determine whether the entire amount of the security deposit is to be returned to the customer as the customer is now in a position that it would be exempt from paying a security deposit under section 2.4.9 or 2.4.11 had it not already paid a security deposit or whether the amount of the security deposit is to be adjusted based on a re-calculation of the maximum amount of the security deposit under section 2.4.12 or 2.4.13.

2.4.22A For the purposes of section 2.4.22, where a residential customer has paid a security deposit in instalments, a distributor shall conduct a review of the customer's security deposit in the calendar year in which the anniversary of the first instalment occurs and thereafter at the next review as required by this Code.

2.4.23 A customer may, no earlier than 12 months after the payment of a security deposit or the making of a prior demand for a review, demand in writing that a distributor undertake a review to determine whether the entire amount of the security deposit is to be returned to the customer as the customer is now in a position that it would be exempt from paying a security deposit under section 2.4.9 or 2.4.11 had it not already paid a security deposit or whether the amount of the security deposit is to be adjusted based on a re-calculation of the maximum amount of the security deposit under section 2.4.12 or 2.4.13.

2.4.23A For the purposes of section 2.4.23, where a residential customer has paid a security deposit in instalments, the customer shall not be entitled to request a review of the security deposit until 12 months after the first instalment was paid.

2.4.23B A distributor shall give notice to all residential customers, at least annually, that any residential customer that qualifies as an eligible low-income customer may request and receive a refund of any security deposit previously paid to the distributor by the customer**,** after application of the security deposit to any outstanding arrears on the customer's account.

2.4.23C Where an eligible low-income customer requests refund of a security deposit previously paid to a distributor by the customer, the distributor shall advise the customer within 10 days of the request that the balance remaining after application of the security deposit to any outstanding arrears will be credited to his or her account where the remaining amount is less than one month's average billing or, where the remaining amount is equal to or greater than one month's average billing, the customer may elect to receive the refund by cheque and the distributor shall issue a cheque within 11 days of the customer requesting payment by cheque.

2.4.24 Despite section 2.4.22, a distributor is not required to review a security deposit paid prior to February 2, 2004 during the calendar year 2004. Despite section 2.4.23, a customer may not demand a review of a security deposit paid prior to February 2, 2004 until February 1, 2005.

2.4.25 Where the distributor determines in conducting a review under section 2.4.22 or 2.4.23 that some or all of the security deposit is to be returned to the customer, the distributor shall promptly return this amount to the customer by crediting the customer's account or otherwise. Despite sections 2.4.22 and 2.4.23, in the case of a customer in a > 5000 kW demand rate class, where the customer is now in a position that it would be exempt from paying a security deposit under section 2.4.9 or 2.4.11 had it not already paid a security deposit, the distributor is only required to return 50% of the security deposit held by the distributor. Despite section 2.4.20, where the distributor determines in conducting a review under section 2.4.22 or 2.4.23 that the maximum amount of the security deposit is to be adjusted upward, the distributor may require the customer to pay this additional amount at the same time as that customer's next regular bill comes due.

2.4.25A Despite section 2.4.25, where a residential electricity customer is required to adjust the security deposit upwards, a distributor shall permit the customer to pay the adjustment amount in equal instalments paid over a period of at least 6 months. A customer may elect to pay the security deposit over a shorter period of time.

2.4.26 A distributor shall promptly return any security deposit received from the customer upon closure of the customer's account, subject to the distributor's right to use the security deposit to set off other amounts owing by the customer to the distributor. The security deposit shall be returned within six weeks of the closure of an account.

2.4.26A A distributor shall not issue a disconnection notice to a residential customer for non-payment unless the distributor has first applied any security deposit held on account for the customer against any amounts owing at that time and the security deposit was insufficient to cover the total amount owing.

2.4.26B Where a distributor applies all or part of a security deposit to offset amounts owing by a residential customer under section 2.4.26A, the distributor may request that the customer repay the amount of the security deposit that was so applied. The distributor shall allow the residential customer to repay the security deposit in instalments in accordance with section 2.4.20A.

2.4.27 A distributor shall apply a security deposit to the final bill prior to the change in service where a customer changes from SSS to a competitive retailer that uses retailer-consolidated billing or a customer changes billing options from distributor-consolidated billing to split billing or retailer-consolidated billing. A distributor shall promptly return any remaining amount of the security deposit to the customer. A distributor shall not pay any portion of a customer's security deposit to a competitive retailer. Where a change is made from distributor-consolidated billing to split billing, a distributor may retain a portion of the security deposit amount that reflects the non-payment risk associated with the new billing option.

2.4.28 Despite sections 2.4.22, 2.4.23, 2.4.25, 2.4.26 and 2.4.27, where all or part of a security deposit has been paid by a third party on behalf of a customer, the distributor shall return the amount of the security deposit paid by the third party, including interest, where applicable, to the third party. This obligation shall apply where and to the extent that:

- the third party paid all or part (as applicable) of the security deposit directly to the distributor;

- the third party has requested, at the time the security deposit was paid or within a reasonable time thereafter, that the distributor return all or part (as applicable) of the security deposit to it rather than to the customer; and

- there is not then any amount overdue for payment by the customer that the distributor is permitted by this Code to off set using the security deposit.

2.4.29 For the purposes of sections 2.4.9 and 2.4.18, the following customers shall be deemed to be residential customers:

(a) seasonal customers who are not classified as general service customers; and

(b) customers of a distributor with a farm rate class who have farms with a dwelling that is occupied as a residence continuously for at least 8 months of the year, where the customer has a < 50 kW demand.

2.4.30 A customer that is a corporation within the meaning of the *Condominium Act, 1998* who has an account with a distributor that:

(a) relates to a property defined in the *Condominium Act, 1998* and comprised predominantly of units that are used for residential purposes; and

(b) relates to more than one unit in the property,

shall be deemed to be a residential customer for the purposes of sections 2.4.9 and 2.4.18 provided that the customer has filed with the distributor a declaration in a form approved by the Board attesting to the customer's status as a corporation within the meaning of the *Condominium Act, 1998*.

2.4.31 Sections 2.4.22 and 2.4.23 shall be applied on the basis that a customer referred to in section 2.4.30 is a residential customer even if the customer paid the security deposit prior to the date on which section 2.4.30 came into force.

2.4.32 Despite any other provision of this Code and despite the billing cycle that would otherwise be applicable based on the distributor's normal practice as documented in its Conditions of Service, in managing customer non-payment risk a distributor may:

(a) bill a customer on a bi-weekly basis, if the value of that customer's electricity bill over 12 consecutive months falls between 51% and 100% of the distributor's approved distribution revenue requirement over that 12-month period; or

(b) bill a customer on a weekly basis, if the value of that customer's electricity bill over 12 consecutive months exceeds 100% of the distributor's approved distribution revenue requirement over that 12-month period.

For the purposes of determining whether this section applies in relation to a customer, a distributor may consider the value of the customer's electricity bill in the 12-month period preceding the coming into force of this section.

2.4.33 A distributor shall not bill a customer in accordance with section 2.4.32 unless the distributor has given the customer at least 42 days notice before issuance of the first bi-weekly or weekly bill, as the case may be.

2.4.34 Where a distributor is billing a customer in accordance with section 2.4.32 or section 2.4.36, the distributor shall resume billing the customer in accordance with the billing cycle that would otherwise be applicable based on the distributor's normal practice as documented in its Conditions of Service if the value of that customer's annual electricity bill over 12 consecutive months falls below 51% of the distributor's distribution revenue over that 12-month period.

2.4.35 Where a distributor is billing a customer in accordance with section 2.4.32(b), the distributor shall bill the customer as follows if the value of that customer's annual electricity bill over 12 consecutive months falls between 51% and 100% of the distributor's distribution revenue over that 12-month period:

(a) in accordance with the billing cycle that would otherwise be applicable based on the distributor's normal practice as documented in its Conditions of Service; or

(b) in accordance with section 2.4.32(a) or section 2.4.36.

2.4.36 Despite any other provision of this Code, a distributor that intends to bill or is billing a customer in accordance with section 2.4.32 may, in lieu of such billing, negotiate alternative arrangements with the customer, including in relation to a lesser frequency of billing or in relation to the giving or retention of security deposits.

2.5 Frequency and Notice of Customer Reclassification and Notice of kVA Billing

2.5.1 A distributor shall, at least once in each calendar year, review each non-residential customer's rate classification to determine whether, based on the rate classification requirements set out in the distributor's rate order, the customer should be assigned to a different rate class. Subject to section 2.5.3, other than at the request of the non-residential customer a distributor may not change a non-residential customer's rate classification more than once in any calendar year.

2.5.2 A distributor shall review a non-residential customer's rate classification upon being requested to do so by the customer to determine whether, based on the rate classification requirements set out in the distributor's rate order, the customer should be assigned to a different rate class. Subject to section 2.5.4, a distributor is not required to respond to more than one such customer request in any calendar year.

2.5.3 A distributor may review a non-residential customer's rate classification at any time if the customer's demand falls outside the upper or lower limits applicable to the customer's current rate classification for a period of five consecutive months.

2.5.4 A distributor shall review a non-residential customer's rate classification upon being requested to do so by the customer at any time if the customer's demand falls outside the upper or lower limits applicable to the customer's current rate classification for a period of five consecutive months.

2.5.5 Where a distributor assigns a non-residential customer to a different rate class as a result of a review initiated by the distributor, the distributor shall give the customer written notice of the reclassification no less than one billing cycle before the reclassification takes effect for billing purposes.

2.5.6 A distributor that charges a non-residential customer on the basis of 90% of the kVA reading of the customer's meter rather than on the basis of the kW reading of the customer's reading shall include on all bills issued to that customer a message to the effect that billing is based on 90% of the kVA reading.

2.6 Bill Issuance and Payment

2.6.1 A distributor shall include on each bill issued to a customer the date on which the bill is printed.

2.6.2 Except as otherwise permitted by this Code, a distributor shall not treat a bill issued to a customer as unpaid, and shall not impose any late payment or other charges associated with non-payment, until the applicable minimum payment period set out in section 2.6.3 has elapsed.

2.6.3 For the purposes of section 2.6.2, the minimum payment period shall be 16 days from the date on which the bill was issued to the customer.

A distributor may provide for longer minimum payment periods, provided that any such longer minimum payment periods are documented in the distributor’s Conditions of Service.

2.6.4 For the purposes of section 2.6.3, a bill will be deemed to have been issued to a customer:

(a) if sent by mail, on the third day after the date on which the bill was printed by the distributor;
(b) if made available over the internet, on the date on which an e-mail is sent to the customer notifying the customer that the bill is available for viewing over the internet;
(c) if sent by e-mail, on the date on which the e-mail is sent; or
(d) if sent by more than one of the methods listed in paragraphs (a) to (c), on whichever date of deemed issuance occurs last.

2.6.5 A distributor shall apply the following rules for purposes of determining the date on which payment of a bill has been received from a customer:

(a) if paid by mail, three days prior to the date on which the distributor receives the payment;
(b) if paid at a financial institution or electronically, on the date on which the payment is acknowledged or recorded by the customer’s financial institution; or
(c) if paid by credit card issued by a financial institution, on the date and at the time that the charge is accepted by the financial institution.

2.6.6 Where a bill issued to a residential customer includes charges for goods or services other than electricity charges, a distributor shall allocate any payment made by the customer first to the electricity charges and then, if funds are remaining, to the charges for other goods or services.

2.6.6.1 Section 2.6.6 does not apply to existing joint billing agreements until the renewal date of such agreements or 2 years, whichever comes earlier, and thereafter the provisions of section 2.6.6 will be deemed applicable.

2.6.6.2A Where payment on account of a bill referred to in section 2.6.6 or 2.6.6.1 is sufficient to cover electricity charges, security deposits and billing adjustments, the distributor shall not impose late payment charges, issue a disconnection notice or disconnect electricity supply.

2.6.6.2B Subject to section 2.6.6.1, where payment on account of a bill referred to in section 2.6.6 or 2.6.6.1 is not sufficient to cover electricity charges, security deposits and billing adjustments, the distributor shall allocate the payments in the following order: electricity charges as defined in section 2.6.6.3, payments towards an arrears payment agreement, outstanding security deposit, under-billing adjustments and non-electricity charges.

2.6.6.3 For the purposes of this section, “electricity charges” are:

(a) charges that appear under the sub-headings “Electricity”, Delivery”, “Regulatory Charges” and “Debt Retirement Charge” as described in Ontario Regulation 275/04 (*Information on Invoices to Low-volume Consumers of Electricity)* made under the Act, and all applicable taxes on those charges;
(b) where applicable, charges prescribed by regulations under section 25.33 of the *Electricity Act* and all applicable taxes on those charges; and
(c) Board-approved specific service charges, including late payment charges, and such other charges and applicable taxes associated with the consumption of electricity as may be required by law to be included on the bill issued to the customer or as may be designated by the Board for the purposes of this section, but not including security deposits or amounts owed by a customer pursuant to an arrears payment agreement or a billing adjustment.

2.6.7 For the purposes of section 2.6, a distributor shall apply the following rules relating to the computation of time:

(a) where there is reference to a number of days between two events, the days shall be counted by excluding the day on which the first event happens and including the day on which the second event happens;
(b) where the time for doing an act expires on a day that is not a business day, the act may be done on the next day that is a business day;
(c) where an act, other than payment by a customer, occurs on a day that is not a business day, it shall be deemed to have occurred on the next business day;
(d) where an act, other than payment by a customer, occurs after 5:00 p.m., it shall be deemed to have occurred on the next business day; and
(e) receipt of a payment by a customer is effective on the date that the payment is made, including payments made after 5:00 p.m.

For the purposes of this section, a “business day” is any day other than a Saturday or a holiday as defined in section 88 of the *Legislation Act, 2006*.

2.7 Arrears Payment Agreements

2.7.1 A distributor shall make available to any residential electricity customer who is unable to pay his or her outstanding electricity charges, as defined in section 2.6.6.3, the opportunity to enter into an arrears payment agreement with the distributor. The arrears payment agreement shall include, at a minimum, the terms and conditions specified in sections 2.7.1.1 – 2.7.5 inclusive.

2.7.1A If a distributor enters into discussions with a residential customer and offers an arrears agreement but the customer declines to enter into an arrears agreement, the distributor may proceed with disconnection and is not required to offer an arrears agreement to such a customer after disconnection.

2.7.1.1 Before entering into an arrears payment agreement under section 2.7, a distributor shall apply any security deposit held on account of the customer against any electricity charges owing at the time.

2.7.1.2 As part of the arrears payment agreement, a distributor may require that the customer pay a down payment of up to 15% of the electricity charge arrears accumulated, inclusive of any applicable late payment charges but excluding other service charges, when entering into the arrears management program.

2.7.1.3 Where an eligible low-income customer enters into an arrears payment agreement for the first time or subsequent to having successfully completed a previous arrears payment agreement as an eligible low-income customer, a distributor may require that the customer pay a down payment of up to 10% of the electricity charge arrears accumulated, inclusive of any applicable late payment charges but excluding other service charges.

2.7.2 The arrears payment agreement referred to in section 2.7.1 shall allow the residential electricity customer to pay all remaining electricity charges that are then overdue for payment as well as the current bill amount if the customer elects to do so, after applying a security deposit under section 2.7.1.1, and the down payment referred to in section 2.7.1.2, including all electricity-related service charges that have accrued to the date of the agreement, over the following periods:

(a) a period of at least 5 months, where the total amount of the electricity charges remaining overdue for payment is less than twice the customer's average monthly billing amount;

(b) a period of at least 10 months, where the total amount of the electricity charges remaining overdue for payment is equal to or exceeds twice the customer's average monthly billing amount;

(c) in the case of an eligible low-income customer, a period of at least 8 months, where the total amount of the electricity charges remaining overdue for payment is less than or equal to 2 times the customer's average monthly billing amount;

(d) in the case of an eligible low-income customer, a period of at least 12 months where the total amount of the electricity charges remaining overdue for payment exceeds 2 times the customer's average monthly billing amount and is less than or equal to 5 times the customer's average monthly billing amount; or

(e) in the case of an eligible low-income customer, a period of at least 16 months where the total amount of the electricity charges remaining overdue for payment exceeds 5 times the customer's average monthly billing amount.

2.7.3 For the purposes of section 2.7.2, the customer's average monthly billing amount shall be calculated by taking the aggregate of the total electricity charges billed to the customer in the preceding 12 months and dividing that value by 12. If the customer has been a customer of the distributor for less than 12 months, the customer's average monthly billing amount shall be based on a reasonable estimate made by the distributor. For the purposes of this section, "electricity charges" has the same meaning as in section 2.6.6.3.

2.7.4 Where a residential customer defaults on more than one occasion in making a payment in accordance with an arrears payment agreement, or a payment on account of a current electricity charge billing, a security deposit amount due or an under-billing adjustment, the distributor may cancel the arrears payment agreement.

2.7.4.1 If the distributor cancels an arrears payment agreement pursuant to section 2.7.4, the distributor will give written notice of cancellation to the customer and to any third party designated by the customer under section 2.7.4.1A at least 10 days before the effective date of the cancellation.

2.7.4.1A Where, at the time of entering into an arrears payment agreement a customer has designated a third party to receive notice of cancellation of the arrears payment agreement, the distributor shall provide notice of cancellation to such third party.

2.7.4.1B A distributor shall accept electronic mail (e-mail) or telephone communications from the customer for purposes of section 2.7.4.1A.

2.7.4.2 If the customer makes payment of all amounts due pursuant to the arrears payment agreement as of the cancellation date referred to in section 2.7.4.1 and makes such payment on or before the cancellation date, the distributor shall reinstate the arrears payment agreement.

2.7.4.3 Where an eligible low-income customer defaults on more than two occasions in making a payment in accordance with an arrears payment agreement, or a payment on account of a current electricity charge billing or an under-billing adjustment, the distributor may cancel the arrears payment agreement.

2.7.4.4 For purposes of sections 2.7.4 and 2.7.4.3, the defaults must occur over a period of at least 2 months before the distributor may cancel the arrears payment agreement.

2.7.5 A distributor shall make available to a residential electricity customer a second arrears payment agreement if the customer so requests, provided that 2 years or more has passed since a first arrears payment agreement was entered into and provided that the customer performed his or her obligations under the first arrears payment agreement.

2.7.5.1 In the case of an eligible low-income customer, the distributor shall allow such a customer to enter into a subsequent arrears payment agreement upon successful completion of the previous arrears payment agreement on the following terms:

i) If a second or subsequent arrears agreement is requested less than 12 months from the date of completion of the previous arrears payment agreement, then the standard arrears payment agreement terms applicable to all residential customers under sections 2.7.1 to 2.7.4.1 also apply to the eligible low-income customer; or

ii) If a second or subsequent arrears agreement is requested 12 months or more from the date of completion of the previous arrears payment agreement, the eligible low-income customer shall be entitled to the arrears payment agreement terms set out in sections 2.7.1.3, 2.7.2(c), 2.7.2(d), 2.7.2(e), 2.7.4.3 and 2.7.4.4.

2.7.6 Notwithstanding the definition of "electricity charges" in section 2.6.6.3, and subject to section 2.7.6A, where an eligible low-income customer enters into an arrears payment agreement with a distributor for the first time or subsequent to having successfully completed a previous arrears payment agreement as an eligible low-income customer, the distributor shall waive any service charges specifically related to collection, disconnection, non-payment or load control devices and such charges shall not be included in the arrears payment agreement.

2.7.6A The distributor is not required to waive any late payment charges, as described in section 2.6.6.3, that accrue to the date of the arrears payment agreement but no further late payment charges may be imposed on an eligible low-income customer after he or she has entered into an arrears payment agreement with the distributor in respect of the amount that is the subject of that agreement.

2.7.7 The distributor shall not disconnect the property of a residential customer, for failing to make a payment subject to an arrears payment agreement, unless the customer is in default, according to sections 2.7.4 or 2.7.4.3, and 2.7.4.4, and the distributor has cancelled the arrears payment agreement in accordance with the provisions of this Code.

2.7.8 In the event a residential electricity customer failed to perform his or her obligations under a previous arrears payment agreement and the distributor terminated the agreement pursuant to section 2.7.4, the distributor may require that the customer wait 1 year after termination of the previous agreement before entering into another arrears payment agreement with the distributor.

2.8 Opening and Closing of Accounts

2.8.1 Where a distributor opens an account for a property in the name of a person at the request of a third party, the distributor shall within 15 days of the opening of the account send a letter to the person advising of the opening of the account and requesting that the person confirm that he or she agrees to be the named customer. If the distributor does not receive confirmation from the intended customer, within 15 days of the date of the letter, the distributor shall advise the third party that the account will not be set up as requested.

2.8.1.1 The distributor is not required to send a letter advising of the opening of the account where the request to open the account is made in writing by the person's solicitor or person in possession of a valid Power of Attorney for the person.

2.8.2 Despite any other provision of this Code, with the exception of the parties mentioned in section 2.8.1.1, where a distributor has opened an account for a property in the name of a person at the request of a third party, the distributor shall not seek to recover from that person any charges for service provided to the property unless the person has agreed to be the customer of the distributor in relation to the property.

2.8.3 Despite any other provision of this Code, with the exception of the parties mentioned in section 2.8.1.1 or an agreement under section 2.8.3A, where a distributor receives a request to close or transfer an account in relation to a rental unit in a residential complex as defined in the *Residential Tenancies Act, 2006* or another residential property, the distributor shall not seek to recover any charges for service provided to that rental unit or residential property after closure of the account from any person, including the landlord for the residential complex or a new owner of the residential property, unless the person has agreed to assume responsibility for those charges.

2.8.3A A distributor may enter into an agreement with a landlord whereby the landlord agrees to assume responsibility for paying for continued service to the rental property after closure of a tenant's account.

2.8.4 For the purposes of section 2.8, the requirement for an agreement in writing includes agreements in electronic form in accordance with the *Electronic Commerce Act, 2000*.

2.8.4A For the purposes of sections 2.8.1, 2.8.2 and 2.8.3, the agreement may be established by verbal request over the telephone provided that a recording of the verbal request is retained by the distributor for 24 months thereafter.

2.8.4B For the purposes of section 2.8.3A, the agreement may be established by verbal request over the telephone provided that a recording of the verbal request is retained by the distributor for the length of the agreement, plus an additional 6 months.

2.8.5 Nothing in sections 2.8.1 – 2.8.4B inclusive is intended to void or cancel any binding agreements for service existing as of the effective date of these amendments or any pre-existing agreements between landlords and distributors.

2.9 Use of Load Control Devices

2.9.1. A distributor may install a load control device instead of disconnecting supply to a customer for non-payment, provided that the distributor complies with the provisions set out in sections 2.9.3, 2.9.3A, 2.9.3B, 2.9.3C, 2.9.4, 2.9.5 and 2.9.6.

2.9.1A Where a customer voluntarily requests the installation or continued use of a load limiter device, the distributor shall install a load limiter device provided the distributor ordinarily provides such a service.

2.9.2 Where a distributor is notified by a Social Service Agency or Government Agency that the agency is assessing the customer for Emergency Financial Assistance, the distributor shall refrain from installing a load control device for a period of 21 days after receiving such notification.

2.9.3 When the distributor installs a load limiter device, either for non-payment or at the customer's request, it shall also deliver a written notice to the customer explaining in plain language the operation of the device, the maximum capacity of the device, how to reset the device if the maximum capacity is exceeded ,as well as a telephone number for the customer to obtain further information and an emergency telephone number to contact if the capacity is exceeded and the customer cannot manually reset the device for any reason.

2.9.3A When the distributor installs a load limiter device for non-payment that cannot be manually reset by the customer after the maximum limit is triggered, then the distributor must provide a 24-hour telephone number the customer may call to have the load limiter device remotely reset.

2.9.3B When the distributor installs a timed load interrupter for non-payment, it shall also deliver a written notice to the customer explaining in plain language the effect of the device on service and a telephone number for the customer to obtain further information.

2.9.3C When a distributor installs a load control device for non-payment, the distributor shall also provide to the customer:

(a) the Fire Safety Notice of the Office of the Fire Marshal; and

(b) any other public safety notices or information bulletins issued by public safety authorities and provided to the distributor, which provide information to consumers respecting dangers associated with the disconnection of electricity service.

2.9.4 A load control device may not be installed at a residential customer’s property during the course of an arrears payment agreement, unless the agreement has been terminated in accordance with the provisions of this Code**.**

2.9.5 Where a distributor had previously installed a load control device for non-payment and the residential customer then enters into an arrears payment agreement, the distributor shall remove the device within 2 business days of the customer entering into an arrears payment agreement.

2.9.5A Despite sections 2.9.4, 2.9.5 and 7.10.1(b), a customer may request the installation or continued use of the load limiter device during the course of the arrears payment agreement where the distributor ordinarily provides such a service.

2.9.6 Subject to section 2.9.5, where a load control device was installed by a distributor for non-payment, the distributor shall remove the load control device within 2 business days of an outstanding account being paid in full.

3 CONNECTIONS AND EXPANSIONS

3.1 Connections

3.1.1 In establishing its connection policy as specified in its Conditions of Service, and determining how to comply with its obligations under section 28 of the *Electricity Act*, a distributor may consider the following reasons to refuse to connect, or continue to connect, a customer:

(a) contravention of the laws of Canada or the Province of Ontario including the Ontario Electrical Safety Code;

(b) violation of conditions in a distributor's licence;

(c) materially adverse effect on the reliability or safety of the distribution system;

(d) imposition of an unsafe worker situation beyond normal risks inherent in the operation of the distribution system;

(e) a material decrease in the efficiency of the distributor's distribution system;

(f) a materially adverse effect on the quality of distribution services received by an existing connection; and

(g) if the person requesting the connection owes the distributor money for distribution services, or for non-payment of a security deposit. The distributor shall give the person a reasonable opportunity to provide the security deposit consistent with sections 2.4.20 and 2.4.20A.

3.1.2 A distributor shall ensure that all electrical connections to its system meet the distributor’s design requirements, unless the electrical connections are separated by a protection device that has been approved by the distributor. If an electrical connection does not meet the distributor’s design requirements, a distributor may refuse connection.

3.1.3 If a distributor refuses to connect a customer, the distributor shall inform the person requesting the connection of the reason(s) for not connecting and, where the distributor is able to provide a remedy, make an offer to connect. If the distributor is unable to provide a remedy to resolve the issue, it is the responsibility of the customer to do so before a connection may be made.

3.1.4 For residential customers, a distributor shall define a basic connection and recover the cost of the basic connection as part of its revenue requirement. The basic connection for each customer shall include, at a minimum:

(a) supply and installation of overhead distribution transformation capacity or an equivalent credit for transformation equipment; and
(b) up to 30 meters of overhead conductor or an equivalent credit for underground services.

3.1.5 For non-residential customers, a distributor may define a basic connection by rate class and recover the cost of connection either as part of its revenue requirement, or through a basic connection charge to the customer.

3.1.6 All customer classes shall be subject to a variable connection charge to be calculated as the costs associated with the installation of connection assets above and beyond the basic connection. A distributor may recover this amount from a customer through a connection charge or equivalent payment.

3.2 Expansions

3.2.1 If a distributor must construct new facilities to its main distribution system or increase the capacity of existing distribution system facilities in order to be able to connect a specific customer or group of customers, the distributor shall perform an initial economic evaluation based on estimated costs and forecasted revenues, as described in Appendix B, of the expansion project to determine if the future revenue from the customer(s) will pay for the capital cost and on-going maintenance costs of the expansion project.

3.2.2 If the distributor's offer was an estimate, the distributor shall carry out a final economic evaluation once the facilities are energized. The final economic evaluation shall be based on forecasted revenues, actual costs incurred (including, but not limited to, the costs for the work that was not eligible for alternative bid, and any transfer price paid by the distributor to the customer) and the methodology described in Appendix B.

3.2.3 If the distributor's offer was a firm offer, and if the alternative bid option was chosen and the facilities are transferred to the distributor, the distributor shall carry out a final economic evaluation once the facilities are energized. The final economic evaluation shall be based on the amounts used in the firm offer for costs and forecasted revenues, any transfer price paid by the distributor to the customer, and the methodology described in Appendix B.

3.2.4 The capital contribution that a distributor may charge a customer other than a generator or distributor to construct an expansion shall not exceed that customer's share of the difference between the present value of the projected capital costs and on-going maintenance costs for the facilities and the present value of the projected revenue for distribution services provided by those facilities. The methodology and inputs that a distributor shall use to calculate this amount are described in Appendix B.

3.2.5 The capital contribution that a distributor may charge a generator to construct an expansion to connect a generation facility to the distributor's distribution system shall not exceed the generator's share of the present value of the projected capital costs and on-going maintenance costs for the facilities. Projected revenue and avoided costs from the generation facility shall be assumed to be zero, unless otherwise determined by rates approved by the Board. The methodology and inputs that a distributor shall use to calculate this amount are described in Appendix B.

3.2.5A Notwithstanding section 3.2.5 but subject to section 3.2.5B, a distributor shall not charge a generator to construct an expansion to connect a renewable energy generation facility:

(a) if the expansion is in a Board-approved plan filed with the Board by the distributor pursuant to the deemed condition of the distributor's licence referred to in paragraph 2 of subsection 70(2.1) of the Act, or is otherwise approved or mandated by the Board; or
(b) in any other case, for any costs of the expansion that are at or below the renewable energy generation facility's renewable energy expansion cost cap.

For greater clarity, the distributor shall bear all costs of constructing an expansion referred to in (a) and, in the case of (b), shall bear all costs of constructing the expansion that are at or below the renewable energy generation facility's renewable energy expansion cost cap.

3.2.5B Where an expansion is undertaken in response to a request for the connection of more than one renewable energy generation facility, a distributor shall not charge any of the requesting generators to construct the expansion:

(a) if the expansion is in a Board-approved plan filed with the Board by the distributor pursuant to the deemed condition of the distributor's licence referred to in paragraph 2 of subsection 70(2.1) of the Act, or is otherwise approved or mandated by the Board; or

(b) in any other case, for any costs of the expansion that are at or below the amount that results from adding the total name-plate rated capacity of each renewable energy generation facility referred to in section 6.2.9(a) (in MW) and then multiplying that number by $90,000.

For greater clarity, the distributor shall bear all costs of constructing an expansion referred to in (a) and, in the case of (b), shall bear all costs of constructing the expansion that are at or below the number that results from the calculation referred to in (b).

3.2.5C Where, in accordance with the calculation referred to in section 3.2.5B(b), a capital contribution is payable by the requesting generators, the distributor shall apportion the amount of the capital contribution among the requesting generators on a pro-rata basis based on the total name-plate rated capacity of the renewable energy generation facility referred to in section 6.2.9(a) (in MW).

3.2.6 If a shortfall between the present value of the projected costs and revenues is calculated under section 3.2.1, the distributor may propose to collect all or a portion of that amount from the customer in the form of a capital contribution, in accordance with the distributor's documented policy on capital contributions by customer class.

3.2.7 If the capital contribution amount resulting from the final economic evaluation provided for in section 3.2.2 or 3.2.3 differs from the capital contribution amount resulting from the initial economic evaluation calculation, the distributor shall obtain from the customer, or credit the customer for, any difference between the two calculations.

3.2.8 If an expansion is needed in order for a distributor to connect a customer, the distributor shall make an initial offer to connect the customer and build the expansion. A distributor's initial offer shall include, at no cost to the customer:

(a) a statement as to whether the offer is a firm offer or is an estimate of the costs that would be revised in the future to reflect actual costs incurred;

(b) a reference to the distributor's Conditions of Service and information on how the customer requesting the connection may obtain a copy of them;

(c) a statement as to whether a capital contribution will be required from the customer;

(d) a statement as to whether an expansion deposit will be required from the customer and if the distributor will require an expansion deposit from the customer, the amount of the expansion deposit that the customer will have to provide; and

(e) a statement as to whether the connection charges referred to in sections 3.1.5 and 3.1.6 will be charged separately from the capital contribution referred to in section 3.2.8(c), and a description of, and if known, the amount for, those connection charges.

3.2.9 If the distributor will require a customer to pay a capital contribution, the distributor must, in addition to complying with section 3.2.8, also include in its initial offer, at no cost to the customer:

(a) the amount of the capital contribution that the customer will have to pay for the expansion;

(b) the calculation used to determine the amount of the capital contribution to be paid by the customer including all of the assumptions and inputs used to produce the economic evaluation as described in Appendix B;

(c) a statement as to whether the offer includes work for which the customer may obtain an alternative bid and, if so, the process by which the customer may obtain the alternative bid;

(d) a description of, and costs for, the work that is eligible for alternative bid and the work that is not eligible for alternative bid associated with the expansion broken down into the following categories:

(i) labour (including design, engineering and construction);

(ii) materials;

(iii) equipment; and

(iv) overhead (including administration);

(e) an amount for any additional costs that will occur as a result of the alternative bid option being chosen (including, but not limited to, inspection costs);

(f) if the offer is for a residential customer, a description of, and the amount for, the cost of the basic connection referred to in section 3.1.4 that has been factored into the economic evaluation; and

(g) if the offer is for a non-residential customer and if the distributor has chosen to recover the non-residential basic connection charge as part of its revenue requirement, a description of, and the amount for, the connection charges referred to in section 3.1.5 that have been factored into the economic evaluation.

3.2.10 Once the customer has accepted the distributor's offer, and if the customer requests it, the distributor shall provide to the customer, at cost, an itemized list of the costs for the major items in each of the categories listed in section 3.2.9(d) and shall be done in the following manner:

(a) if the customer has not chosen to pursue an alternative bid, the distributor shall provide the itemized list for all of the work; or

(b) if the customer has chosen to pursue the alternative bid option, the distributor shall only be required to provide the itemized list for the work that is not eligible for alternative bid.

3.2.11 If the customer submits revised plans or requires additional design work, the distributor may provide, at cost, a new offer based on the revised plans or the additional design work.

3.2.12 The distributor shall provide the customer with the calculation used to determine the final capital contribution amount including all of the assumptions and inputs used to produce the final economic evaluation as provided for in sections 3.2.2 and 3.2.3. The distributor shall provide the final economic evaluation and final capital contribution amount to the customer at no cost to the customer.

3.2.13 The last sentence of section 3.2.12 does not apply to a customer who is a generator or is proposing to become a generator unless the customer's proposed or existing generation facility is an emergency backup generation facility.

3.2.14 Where the distributor requires a capital contribution from the customer, the distributor shall allow the customer to obtain and use alternative bids for the work that is eligible for alternative bid. The distributor shall require the customer to use a qualified contractor for the work that is eligible for alternative bid provided that the customer agrees to transfer the expansion facilities that are constructed under the alternative bid option to the distributor upon completion.

3.2.15 The following activities are not eligible for alternative bid:

(a) distribution system planning; and

(b) the development of specifications for any of the following:

(i) the design of an expansion;

(ii) the engineering of an expansion; and

(iii) the layout of an expansion.

3.2.15A Work that requires physical contact with the distributor's existing distribution system is not eligible for alternative bid unless the distributor decides in any given case to allow such work to be eligible for alternative bid.

3.2.15B Despite any other provision of this Code, decisions related to the temporary de-energization of any portion of the distributor's existing distribution system are the sole responsibility of the distributor. Where the temporary de-energization is required in relation to work that is being done under alternative bid, the distributor shall apply the same protocols and procedures to the de-energization as it would if the customer had not selected the alternative bid option.

3.2.16 If a customer chooses to pursue an alternative bid and uses the services of a qualified contractor for the work that is eligible for alternative bid, the distributor shall:

(a) require the customer to complete all of the work that is eligible for alternative bid;

(b) require the customer to:

(i) select and hire the contractor;

(ii) pay the contractor's costs for the work that is eligible for alternative bid; and

(iii) assume full responsibility for the construction of that aspect of the expansion;

(c) require the customer to be responsible for administering the contract (including the acquisition of all required permissions, permits and easements) or have the customer pay the distributor to do this activity;

(d) require the customer to ensure that the work that is eligible for alternative bid is done in accordance with the distributor's distribution system planning and the distributor's specifications for any of the following:

(i) the design of the expansion;

(ii) the engineering of the expansion; and

(iii) the layout of the expansion

(d.1) require the customer to obtain the distributor’s review and approval of plans for the design, engineering, layout, and work execution for the work that is eligible for alternative bid to ensure conformance with the distribution system planning and specifications referred to in paragraph (d) prior to commencing that work; and

(e) inspect and approve, at cost, all aspects of the constructed facilities as part of a system commissioning activity, prior to connecting the constructed facilities to the existing distribution system.

3.2.17 In addition to the capital contribution amounts in sections 3.2.4 and 3.2.5, the distributor may also charge a customer that chooses to pursue an alternative bid any costs incurred by the distributor associated with the expansion including, but not limited to, the following:

(a) costs for additional design, engineering, or installation of facilities required to complete the project;

(a.1) costs associated with any temporary de-energization of any portion of the existing distribution system that is required in relation to an expansion that is constructed under the alternative bid option;

(a.2) costs associated with the review and approval referred to in section 3.2.16(d.1);

(b) costs for administering the contract between the customer and the contractor hired by the customer if the distributor is asked to do so by the customer and the distributor agrees to do it; and

(c) costs for inspection or approval of the work performed by the contractor hired by the customer.

When the customer transfers the expansion facilities to the distributor in accordance with section 3.2.18 and 3.2.19, the charges referred to above shall be included as part of the customer's costs for the purposes of determining the transfer price.

3.2.18 When the customer transfers the expansion facilities that were constructed under the alternative bid option to the distributor, and provided that the distributor has inspected and approved the constructed facilities, the distributor shall pay the customer a transfer price. The transfer price shall be the lower of the cost to the customer to construct the expansion facilities or the amount set out in the distributor's initial offer to do the work that is eligible for alternative bid. If the customer does not provide the distributor with the customer's cost information in a timely manner, then the distributor may use the amount for the work that is eligible for alternative bid as set out in its initial offer for the transfer price instead of the customer's cost.

3.2.19 Where a distributor is required to pay a transfer price under section 3.2.18, the transfer price shall be considered a cost to the distributor for the purposes of completing the final economic evaluation.

3.2.20 For expansions that require a capital contribution, a distributor may require the customer to provide an expansion deposit for up to 100% of the present value of the forecasted revenues as described in Appendix B. For expansions that do not require a capital contribution, a distributor may require the customer to provide an expansion deposit for up to 100% of the present value of the projected capital costs and on-going maintenance costs of the expansion project.

3.2.21 If an expansion deposit is collected under section 3.2.20, the expansion deposit shall cover both the forecast risk (the risk associated with whether the projected revenue for the expansion will materialize as forecasted) and the asset risk (the risk associated with ensuring that the expansion is constructed, that it is completed to the proper design and technical standards and specifications, and that the facilities operate properly when energized) related to the expansion.

3.2.22 If the alternative bid option was chosen, a distributor shall be allowed to retain and use the expansion deposit to cover the distributor's costs if the distributor must complete, repair, or bring up to standard the facilities. Complete, repair, or bring up to standard includes costs the distributor incurs to ensure that the expansion is completed to the proper design and technical standards and specifications, and that the facilities operate properly when energized.

3.2.23 Once the facilities are energized and subject to sections 3.2.22 and 3.2.24, the distributor shall annually return the percentage of the expansion deposit in proportion to the actual connections (for residential developments) or actual demand (for commercial and industrial developments) that materialized in that year (i.e., if twenty percent of the forecasted connections or demand materialized in that year, then the distributor shall return to the customer twenty percent of the expansion deposit). This annual calculation shall only be done for the duration of the customer connection horizon as defined in Appendix B. If at the end of the customer connection horizon the forecasted connections (for residential developments) or forecasted demand (for commercial and industrial developments) have not materialized, the distributor shall be allowed to retain the remaining portion of the expansion deposit.

3.2.24 If the alternative bid option was chosen, the distributor may retain up to ten percent of the expansion deposit for a warranty period of up to two years. This portion of the expansion deposit can be applied to any work required to repair the expansion facilities within the two year warranty period. The two year warranty period begins:

(a) when the last forecasted connection in the expansion project materializes (for residential developments) or the last forecasted demand materializes (for commercial and industrial developments); or
(b) at the end of the customer connection horizon as defined in Appendix B,

whichever is first. The distributor shall return any remaining portion of this part of the expansion deposit at the end of the two year warranty period.

3.2.25 Any expansion deposit required under section 3.2.20 shall be in the form of cash, letter of credit from a bank as defined in the *Bank Act*, or surety bond. The distributor shall allow the customer to select the form of the expansion deposit.

3.2.26 Where any expansion deposit is in the form of cash, the distributor shall return the expansion deposit to the customer together with interest in accordance with the following conditions:

(a) interest shall accrue monthly on the expansion deposit commencing on receipt of the total deposit required by the distributor; and
(b) the interest rate shall be at the Prime Business Rate set by the Bank of Canada less 2 percent.

3.2.27 Unforecasted customers that connect to the distribution system during the customer connection horizon as defined in Appendix B will benefit from the earlier expansion and should contribute their share. In such an event, the initial contributors shall be entitled to a rebate from the distributor. A distributor shall collect from the unforecasted customers an amount equal to the rebate the distributor shall pay to the initial contributors. The amount of the rebate shall be determined as follows:

(a) for a period of up to the customer connection horizon as defined in Appendix B, the initial contributor shall be entitled to a rebate without interest, based on apportioned benefit for the remaining period; and

(b) the apportioned benefit shall be determined by considering such factors as the relative name-plate rated capacity of the parties, the relative load level of the parties and the relative line length in proportion to the line length being shared by both parties, as applicable.

3.2.27A Notwithstanding section 3.2.27, when the unforecasted customer is a renewable energy generation facility to which section 3.2.5A or 3.2.5B applies and the customer entitled to a rebate under section 3.2.27 is a load customer or a generation customer to which neither section 3.2.5A nor 3.2.5B applies, the initial contributors shall be entitled to a rebate from the distributor in an amount determined in accordance with section 3.2.27. The distributor shall reduce the connecting renewable energy generation facility's renewable energy expansion cost cap by an amount equal to the rebate. If the amount of the rebate exceeds the connecting renewable generation facility's renewable energy expansion cost cap, the distributor shall also collect the difference from the connecting renewable energy generation customer.

3.2.27B Notwithstanding section 3.2.27, when an unforecasted customer that is a renewable energy generation facility to which section 3.2.5A or 3.2.5B applies (the "unforecasted renewable generator") connects to the distribution system during the customer connection horizon as defined in Appendix B and benefits from an earlier expansion made on or after October 21, 2009 to connect another renewable energy generation facility to which section 3.2.5A or 3.2.5B applies (the "initial renewable generator"), the initial renewable generator shall be entitled to a rebate if the cost of the earlier expansion exceeded the initial renewable generator's renewable energy expansion cost cap. In such a case, the following rules shall apply:

(a) the distributor shall pay to the initial renewable generator a rebate in an amount determined in accordance with section 3.2.27C; and

(b) the distributor shall collect from the unforecasted renewable generator an amount determined in accordance with section 3.2.27C.

For greater certainty, no rebate shall be payable to an initial renewable generator towards the cost of an earlier expansion if the cost of the earlier expansion did not exceed the initial renewable generator's energy expansion cost cap.

3.2.27C For the purposes of section 3.2.27B:

(a) the amount of the rebate payable by the distributor to the initial renewable generator shall be the difference between the amount paid by the initial renewable generator towards the cost of the earlier expansion and the amount that would have been paid by the initial renewable generator towards that cost, determined in accordance with the rules set out in sections 3.2.5B and 3.2.5C, had the earlier expansion been undertaken for both the initial renewable generator and the unforecasted renewable generator. The rebate shall be without interest; and

(b) the amount to be collected from the unforecasted renewable generator shall be the amount that would have been paid by the unforecasted renewable generator towards the cost of the earlier expansion, determined in accordance with the rules set out in sections 3.2.5B and 3.2.5C, had the earlier expansion been undertaken for both the initial renewable generator and the unforecasted renewable generator.

3.2.27D Notwithstanding section 3.2.27, an unforecasted customer that is a load customer or a generation customer to which neither section 3.2.5A or 3.2.5B applies, that connects to the distribution system during the customer connection horizon as defined in Appendix B and that benefits from an earlier expansion made on or after October 21, 2009 to connect a renewable generation facility to which section 3.2.5A or 3.2.5B applies (the "initial renewable generator") shall contribute towards the cost of the earlier expansion. In such a case, the following rules shall apply:

(a) where the cost of the earlier expansion exceeded the initial renewable generator's renewable energy expansion cost cap, the initial renewable generator and the distributor shall be entitled to a rebate in an amount determined in accordance with sections 3.2.27 and 3.2.27E; or

(b) where the cost of the earlier expansion was at or below the initial renewable generator's renewable energy expansion cost cap, the distributor shall be entitled to a rebate in an amount determined in accordance with section 3.2.27.

3.2.27E For the purposes of section 3.2.27D(a), the amount of the rebate shall be apportioned between the initial renewable generator and the distributor on a pro-rata basis based on their respective contributions to the cost of the earlier expansion.

3.2.27F For greater certainty:

(a) sections 3.2.27B and 3.2.27D do not apply in respect of an expansion referred to in section 3.2.5A(a) or 3.2.5B(a);

(b) the amount of the rebate payable to an initial renewable generator under section 3.2.27B or section 3.2.27D(a) shall not exceed the amount paid by the initial renewable generator as a capital contribution towards the cost of the earlier expansion; and

(c) where an earlier expansion referred to in section 3.2.27B or 3.2.27D was made to connect more than one renewable energy generation facility to which section 3.2.5B applies, the amount of the rebate payable to the renewable generators shall be apportioned between them on a pro-rata basis based on the total name-plate rated capacity of each renewable energy generation facility referred to in section 6.2.9(a) (in MW).

3.2.28 A distributor shall prepare all estimates and offers required by section 3.2 in accordance with good utility practice and industry standards.

3.2.29 The distributor shall perform all of its responsibilities and obligations under section 3.2 in a timely manner.

3.2.30 An expansion of the main distribution system includes:

(a) building a new line to serve the connecting customer;

(b) rebuilding a single-phase line to three-phase to serve the connecting customer;

(c) rebuilding an existing line with a larger size conductor to serve the connecting customer;

(d) rebuilding or overbuilding an existing line to provide an additional circuit to serve the connecting customer;

(e) converting a lower voltage line to operate at higher voltage;

(f) replacing a transformer to a larger MVA size;

(g) upgrading a voltage regulating transformer or station to a larger MVA size; and

(h) adding or upgrading capacitor banks to accommodate the connection of the connecting customer.

3.3 Enhancements

3.3.1 A distributor shall continue to plan and build the distribution system for reasonable forecast load growth. A distributor may perform enhancements to its distribution system for purposes of improving system operating characteristics or for relieving system capacity constraints. In determining system enhancements to be performed on its distribution system, a distributor shall consider the following:

(a) good utility practice;

(b) improvement of the system to either meet or maintain required performance-based indices;

(c) current levels of customer service and reliability and potential improvement from the enhancement; and

(d) costs to customers associated with distribution reliability and potential improvement from the enhancement.

3.3.2 Renewable enabling improvements to the main distribution system to accommodate the connection of renewable energy generation facilities are limited to the following:

(a) modifications to, or the addition of, electrical protection equipment;

(b) modifications to, or the addition of, voltage regulating transformer controls or station controls;

(c) the provision of protection against islanding (transfer trip or equivalent);

(d) bidirectional reclosers;

(e) tap-changer controls or relays;

(f) replacing breaker protection relays;

(g) Supervisory Control and Data Acquisition system design, construction and connection;

(h) any other modifications or additions to allow for and accommodate 2-way electrical flows or reverse flows; and

(i) communication systems to facilitate the connection of renewable energy generation facilities.

3.3.3 Subject to section 3.3.4, the distributor shall bear the cost of constructing an enhancement or making a renewable enabling improvement, and therefore shall not charge:

(a) a customer a capital contribution to construct an enhancement; or

(b) a customer that is connecting a renewable energy generation facility a capital contribution to make a renewable enabling improvement.

3.3.4 Section 3.3.3(a) shall not apply to a distributor until the distributor's rates are set based on a cost of service application for the first time following the 2010 rate year.

3.4 Relocation of Plant

3.4.1 When requested to relocate distribution plant, a distributor shall exercise its rights and discharge its obligations in accordance with existing legislation such as the *Public Service Works on Highways Act*, regulations, formal agreements, easements and common law. In the absence of existing arrangements, a distributor is not obligated to relocate the plant. However, the distributor shall resolve the issue in a fair and reasonable manner. Resolution in a fair and reasonable manner shall include a response to the requesting party that explains the feasibility or infeasibility of the relocation and a fair and reasonable charge for relocation based on cost recovery principles.

4 OPERATIONS

4.1 Quality of Supply

4.1.1 A distributor shall follow good utility practice in managing the power quality of the distributor's distribution system and define in its Conditions of Service the quality of service standards to which the distribution system is designed and operated.

4.1.2 A distributor shall maintain a voltage variance standard in accordance with the standards of the Canadian Standards Association CAN3-235. A distributor shall practice reasonable diligence in maintaining voltage levels, but is not responsible for variations in voltage from external forces, such as operating contingencies, exceptionally high loads and low voltage supply from the transmitter or host distributor.

4.1.3 Subject to section 4.7, a distributor shall respond to and take reasonable steps to investigate all consumer power quality complaints and report to the consumer on the results of the investigation.

4.1.4 Except in relation to an investigation conducted under section 4.7, if the source of a power quality problem is caused by the consumer making the complaint, the distributor may seek reimbursement for the time and cost spent to investigate the complaint.

4.1.5 A distributor shall take appropriate actions to control harmonic distortions found to be detrimental to consumers connected to the distribution system. If the distributor is unable to correct a problem without adversely impacting other distribution system consumers, a distributor may choose not to make the corrections. In deciding which actions to take, a distributor should use appropriate industry standards and good utility practice as guidelines.

4.1.6 A distributor shall require a consumer or customer that owns equipment connected to the distribution system to take reasonable steps to ensure that the operation or failure of that equipment does not cause a distribution system outage or disturbance.

4.1.7 A distributor may require that any consumer or customer condition that adversely affects the distribution system be corrected immediately by the consumer or customer at the consumer’s or customer’s cost.

4.1.8 A distributor may direct a consumer or customer connected to its distribution system to take corrective or preventive action on the consumer’s or customer’s electric system when there is a direct hazard to the public or the consumer or customer is causing or could cause adverse effects to the reliability of the distributor’s distribution system. If the situation is not corrected, the distributor may disconnect the consumer or customer in accordance with its disconnection policy.

4.2 Disconnection and Reconnection

4.2.1 A distributor shall establish a process for disconnection and reconnection that specifies timing and means of notification consistent with the *Electricity Act*. In developing physical and business processes for reconnection, a distributor shall consider safety and reliability as a primary requirement. A distributor shall document its business process for disconnection in the distributor's Conditions of Service.

4.2.1.1 Without limiting the generality of the foregoing, prior to disconnecting a property for non-payment, a distributor shall provide to any person that, according to the distributor's Conditions of Service, receives notice of the disconnection:

(a) the Fire Safety Notice of the Office of the Fire Marshal; and
(b) any other public safety notices or information bulletins issued by public safety authorities and provided to the distributor, which provide information to consumers respecting dangers associated with the disconnection of electricity service.

4.2.1.2 A distributor shall include a copy of the notices or bulletins referred to in s. 4.2.1.1 along with any notice of disconnection that is left at the property at the time of actual disconnection for non-payment.

4.2.2 A distributor that intends to disconnect, pursuant to section 31 of the *Electricity Act,* the property of a residential customer for non-payment shall send or deliver a disconnection notice to the customer that contains, at a minimum, the following information:

(a) the date on which the disconnection notice was printed by the distributor;
(b) the earliest and latest dates on which disconnection may occur, in accordance with sections 4.2.3 and 4.2.2.3;
(c) the amount that is then overdue for payment, including all applicable late payment and other charges associated with non-payment to that date;
(d) the amount of any approved service charge(s) that may apply if disconnection occurs, and the circumstances in which each of these charges is payable;
(e) the forms of payment that the customer may use to pay all amounts that are identified as overdue in the disconnection notice, which must at least include payment by credit card issued by a financial institution as described in section 4.2.4 and any other method of payment that the

distributor ordinarily accepts and which can be verified within the time period remaining before disconnection;

(f) the time period during which any given form of payment listed under paragraph (e) will be accepted by the distributor;

(g) that, in order to avoid disconnection if the distributor attends at the customer's property to execute the disconnection, a customer will only be able to pay by credit card issued by a financial institution, unless the distributor, in its discretion, will accept other forms of payment at that time and sets out the other forms of payment in the disconnection notice;

(h) that a disconnection may take place whether or not the customer is at the premises;

(i) that, where applicable, the disconnection may occur without attendance at the customer's premises;

(j) that a Vital Services By-Law may exist in the customer's community and that the customer should contact their local municipality for more information;

(k) that a Board-prescribed standard arrears management program and equal monthly payment plan option may be available to all residential customers, along with contact information for the distributor where the customer can obtain further information;

(k1) that the following additional assistance may be available to an eligible low-income customer, along with contact information for the distributor where the customer can obtain further information about the additional assistance:

i) a Board-prescribed arrears management program, and other expanded customer service provisions, specifically for eligible low-income customers; and

ii) a Board-approved Emergency Financial Assistance program administered through a Social Service Agency or Government Agency;

(k2) that the distributor may install a load control device at the customer's premises in lieu of disconnection; and

(l) any additional option(s) that the distributor chooses, in its discretion, to offer to the customer to avoid disconnection and the deadline for the customer to avail himself or herself of such option(s).

4.2.2.1 A distributor that sends or delivers to a customer a disconnection notice, pursuant to section 31(2) of the *Electricity Act,* for non-payment shall not include that notice in the same envelope as a bill or any other documentation emanating from the distributor.

4.2.2.2 A distributor shall, at the request of a residential customer, send a copy of any disconnection notice issued to the customer for non-payment to a third party designated by the customer for that purpose provided that the request is made no later than the last day of the applicable minimum notice period set out in section 4.2.3. In such a case:

(a) the distributor shall notify the third party that the third party is not, unless otherwise agreed with the distributor, responsible for the payment of any charges for the provision of electricity service in relation to the customer's property; and
(b) the rules set out in sections 2.6.4 and 2.6.7 shall apply, with such modifications as the context may require, for the purposes of determining the date of receipt of the disconnection notice by the third party.

4.2.2.2A A residential customer may, at any time prior to disconnection, designate a third party to also receive any future notice of disconnection and the distributor shall send notice of disconnection to such third party.

4.2.2.2B A distributor shall accept electronic mail (e-mail) or telephone communications from the customer for purposes of section 4.2.2.2A.

4.2.2.3 A disconnection notice issued for non-payment shall expire on the date that is 11 days from the last day of the applicable minimum notice period referred to in section 4.2.3, determined in accordance with the rules set out in section 2.6.7. A distributor may not thereafter disconnect the property of the customer for non-payment unless the distributor issues a new disconnection notice in accordance with section 4.2.2.

4.2.2.4 A distributor shall make reasonable efforts to contact, in person or by telephone, a residential customer to whom the distributor has issued a disconnection notice for non-payment at least 48 hours prior to the scheduled date of disconnection. At that time, the distributor shall:

(a) advise the customer of the scheduled date for disconnection;
(b) advise the customer that a disconnection may take place whether or not the customer is at the premises;
(c) where applicable, advise the customer that the disconnection may occur without attendance at the customer's premises;
(d) advise that the customer has the option to pay amounts owing by credit card issued by a financial institution, in addition to other forms of payment that the distributor will accept at that time and which can be

verified within the time period remaining before disconnection; and advise during what hours such payments may be made;

(e) advise the customer that, if the distributor attends at the customer's property to execute the disconnection, the customer will only be able to pay by credit card issued by a financial institution, unless the distributor, in its discretion, will accept other forms of payment at that time;

(f) advise the customer that a Board-prescribed standard arrears management program and equal monthly payment plan option may be available to all residential customers; the distributor must be prepared to enter into an arrears payment agreement at that time if the customer is eligible under section 2.7;

(f1) advise that the following additional assistance may be available to an eligible low-income customer, along with contact information for the distributor where the customer can obtain further information about the additional assistance:

i) a Board-prescribed arrears management program, and other expanded customer service provisions, specifically for eligible low-income customers; and

ii) a Board-approved Emergency Financial Assistance program administered through a Social Service Agency or Government Agency; and

(g) advise the customer of any additional option(s) that the distributor, in its discretion, wishes to offer to the customer to avoid disconnection.

4.2.2.5 Where a distributor issues a disconnection notice for non-payment in respect of the disconnection of a multi-unit, master-metered building, the distributor shall post a copy of the disconnection notice in a conspicuous place on or in the building promptly after issuance of the notice.

4.2.2.6 A distributor shall suspend any disconnection action for a period of 21 days from the date of notification by a Social Service Agency or Government Agency that it is assessing a residential customer for the purposes of determining whether the customer is eligible to receive such assistance, provided such notification is made within 10 days from the date on which the disconnection notice is received by the customer. Where a residential customer had requested prior to the issuance of the disconnection notice that the distributor also provide a copy of any disconnection notice to a third party, the distributor shall suspend any disconnection action for a period of 21 days from the date of notification by the third party that he, she or it is attempting to arrange assistance with the bill payment, provided such notification is made within 10 days from the date on which the disconnection notice is received by the customer.

4.2.2.7 Despite section 4.2.2.6, upon notification by a Social Service Agency or Government Agency that a customer is not eligible to receive such assistance, or if another third party who was considering the provision of bill assistance decides not to proceed, the distributor may continue its disconnection process. Distributors will have up to 11 days to act on the previous disconnection notice and must make a further reasonable effort to contact the customer in accordance with section 4.2.2.4 prior to executing disconnection.

4.2.3 A distributor shall not disconnect a customer for non-payment until the following minimum notice periods have elapsed.

(a) 60 days from the date on which the disconnection notice is received by the customer, in the case of a residential customer that has provided the distributor with documentation from a physician confirming that disconnection poses a risk of significant adverse effects on the physical health of the customer or on the physical health of the customer's spouse, dependent family member or other person that regularly resides with the customer; or

(b) 10 days from the date on which the disconnection notice is received, in all other cases.

4.2.3.1 For the purposes of section 4.2.3:

(a) where a disconnection notice is sent by mail, the disconnection notice shall be deemed to have been received by the customer on the third business day after the date on which the notice was printed by the distributor;
(b) where a disconnection notice is delivered by personal service, the disconnection notice shall be deemed to have been received by the customer on the date of delivery;
(c) where a disconnection notice is delivered by being posted on the customer's property, the disconnection notice shall be deemed to have been received by the customer on the date of such posting;
(d) "spouse" has the meaning given to it in section 29 of the *Family Law Act*;
(e) "dependent family member" means a "dependent" as defined in section 29 of the *Family Law Act* and also includes a grandparent who, based on need, is financially dependent on the customer; and
(f) the distributor shall apply the rules relating to the computation of time set out in section 2.6.7.

4.2.4 A distributor may disconnect without notice in accordance with a court order or for emergency, safety or system reliability reasons.

4.2.5

(a) Where a distributor has issued a disconnection notice to a residential customer for non-payment, the distributor shall ensure it has the facilities or staff available to permit the customer to pay all amounts that are then overdue for payment by credit card issued by a financial institution. Subject to paragraph (b), this payment option must be offered during the regular business hours of the distributor, from the time the disconnection notice is delivered to a residential customer until the time the distributor's staff attends at the customer's premises to execute the disconnection.

(b) Where a distributor attends at a residential customer's property to execute a disconnection, whether during or after the distributor's regular business hours, the distributor shall ensure it has the facilities or staff available at that time to permit the customer to pay all amounts that are then overdue for payment by credit card issued by a financial institution. The distributor may, in its discretion, also accept other forms of payment at the time of disconnection.

(c) Where a distributor was unsuccessful in its attempt to contact a residential customer 48 hours before the planned disconnection as required under section 4.2.2.4, and the distributor intends to execute the disconnection by attendance at the customer's premises, the distributor shall make a reasonable attempt to communicate with the customer, with due regard for the safety and security of the distributor's personnel, if the customer is at the property, to advise that disconnection will be executed and that payment may be made by credit card issued by a financial institution.

4.2.5.1 The physical process by which a distributor disconnects or reconnects shall reflect good utility practice and consider safety as a primary requirement.

4.2.5.2 A distributor may recover from the customer responsible for the disconnection reasonable costs associated with disconnection, including overdue amounts payable by the customer. A distributor may recover from the customer responsible for the disconnection reasonable costs for repairs of the distributor's physical assets attached to the property in reconnecting the property.

4.2.5.3 A distributor may recover from the person requesting the reconnection any Board approved reconnection charges.

4.2.6 In establishing its disconnection policy as specified in its Conditions of Service, consistent with section 30 and 31 of the *Electricity Act* and good utility practice, a distributor may consider the following reasons for disconnection:

- Adverse effect on the reliability and safety of the distribution system.
- Imposition of an unsafe worker situation beyond normal risks inherent in the operation of the distribution system.
- A material decrease in the efficiency of the distributor's distribution system.
- A materially adverse effect on the quality of distribution services received by an existing connection.
- Inability of the distributor to perform planned inspections and maintenance.
- Failure of the consumer or customer to comply with a directive of a distributor that the distributor makes for purposes of meeting its licence obligations.
- The customer owes the distributor money for distribution services, or for a security deposit. The distributor shall give the customer a reasonable opportunity to provide the security deposit consistent with sections 2.4.20 and 2.4.20A.

4.3 Unauthorized Energy Use

4.3.1 A distributor shall use its discretion in taking action to mitigate unauthorized energy use. Upon identification of possible unauthorized energy use, a distributor shall notify, if appropriate, Measurement Canada, the Electrical Safety Authority, police officials, retailers that service consumers affected by the unauthorized energy use, or other entities.

4.3.2 A distributor shall monitor losses and unaccounted for energy use on an annual basis to detect any upward trends that may indicate the need for management policies to moderate unauthorized energy use.

4.3.3 A distributor may recover from the customer responsible for the unauthorized energy use all reasonable costs incurred by the distributor arising from unauthorized energy use.

4.4 System Inspection Requirements and Maintenance

4.4.1 A distributor shall maintain its distribution system in accordance with good utility practice and performance standards to ensure reliability and quality of electricity service, on both a short-term and long-term basis.

4.4.2 A distributor shall perform inspection activities of its distribution system in accordance with the requirements in Appendix C attached to this Code.

4.4.3 A distributor shall perform more frequent inspections if warranted due to local conditions such as geographic location, climate, environmental conditions, technologies available to perform the inspection, type and vintage of distribution technology in place, manufacturer specifications, system design or relative importance to overall system reliability of a particular piece of equipment or portion of the distributor's distribution system.

4.4.4 A distributor shall perform inspection activities using persons qualified to identify the types of defects that could be discovered during such inspection activities. Persons performing inspection activities shall be trained to protect both themselves and the public, and to respond to emergencies that may arise as a result of inspection activities.

4.4.5 A distributor shall address any defects discovered during the inspection activities within a reasonable period of time after the discovery of the defect. A distributor shall address a defect by scheduling a more detailed inspection, by planning repair activities or by performing any other action that is an affirmative response to the discovery of the defect. A distributor shall have an internal review procedure to ensure that the identified defects and follow-up activities have been addressed appropriately.

4.4.6 A distributor shall determine the methodology by which inspection cycles are structured and the manner in which defects identified during inspection activities are to be repaired in accordance with good utility practice.

4.4.7 A distributor shall notify consumers regarding the expected duration and frequency of planned outages and provide as much advance notice as possible. A distributor shall make all reasonable efforts to minimize the duration and frequency of planned outages. The distributor's policies and procedures with respect to planned outages shall be described in the Conditions of Service.

4.5 Unplanned Outages and Emergency Conditions

4.5.1 A distributor may require a consumer or customer or a party to a joint use agreement to comply with reasonable and appropriate instructions from the distributor during an unplanned outage or emergency situation.

4.5.2 To assist with distribution system outages or emergency response, a distributor may require a customer to provide the distributor emergency access to customer-owned distribution equipment that normally is operated by the distributor or distributor-owned equipment on customer property.

4.5.3 During an emergency, a distributor may interrupt supply to a consumer in response to a shortage of supply or to effect repairs on the distribution system or while repairs are being made to consumer-owned equipment.

4.5.4 A distributor may require consumers or customers with permanently connected emergency backup generation facility to notify the distributor regarding the presence of such equipment.

4.5.5 A distributor shall require that a consumer's or customer's portable or permanently connected emergency backup generation facility complies with all applicable criteria of the Ontario Electrical Safety Code and does not adversely affect the distributor's distribution system.

4.5.6 A distributor shall develop and maintain appropriate emergency plans in accordance with the requirements of the Minister of Energy, Science and Technology and in the Market Rules, regardless of whether the distributor is a wholesale market participant. A distributor's emergency plan shall include, at a minimum, mutual assistance plans with neighbouring distributors or other measures to respond to a wide-spread emergency.

4.5.7 A distributor shall establish outage management policies that include the following:

- Arrangements for on-call personnel in accordance with good utility practice.
- Establishment and operation of a call centre or equivalent telephone service to provide consumers with available information regarding an outage.

- Identification of the location of distribution circuits for emergency services and critical customers such as hospitals, water supply, health care facilities, and designated emergency shelters for coordination with other agencies.

4.6 Health and Safety and Environment

4.6.1 A distributor shall follow good utility practices in operating and maintaining the distribution system and shall abide by safety rules and regulations that apply to routine utility work, including but not limited to the *Occupational Health & Safety Act* R.S.O. 1990 and any associated regulations.

4.6.2 A distributor shall be a member of an industry-specific, recognized health and safety organization in Ontario.

4.6.3 A distributor shall implement an industry recognized health and safety program that includes training and regularly conducted audits. This program also will include Public Education and Public Safety initiatives.

4.6.4 Any problems that a distributor identifies as part of the audit shall be remedied as soon as possible or in accordance with the distributor's health and safety program.

4.6.5 A distributor shall have a corporate policy that addresses environmental stewardship that applies to all of the distributor's operations. A documented program supporting procedures and appropriate training should be in place to ensure compliance with environmental regulations and indicate a proactive approach to environmental damage avoidance.

4.7 Farm Stray Voltage

4.7.1 In this section 4.7:

- ACC–means animal contact current, being the steady state 60 Hz (including harmonics thereof) root mean square alternating current when measured through a 500 Ohm resistor connected between animal contact points;
- ACV–means animal contact voltage, being the steady state 60 Hz (including harmonics thereof) root mean square alternating current

voltage when measured in parallel with a 500 Ohm resistor connected between animal contact points;

- "farm stray voltage" means ACC or ACV occurring at a location on a farm where livestock make contact with it; and
- "livestock farm customer" in respect of a distributor means any customer of the distributor that is engaged principally in livestock husbandry in an area zoned for agricultural use.

4.7.2 A distributor shall initiate a farm stray voltage investigation using the procedure set out in Appendix H where a livestock farm customer provides the distributor with information that reasonably indicates that farm stray voltage may be adversely affecting the operation of the livestock farm customer's farm.

4.7.3 Where an investigation initiated under section 4.7.2 reveals that either:

a) ACC on the farm exceeds 2.0 milliamperes; or
b) ACV on the farm exceeds 1.0 volt,

the distributor shall conduct tests in accordance with the investigation procedure set out in Appendix H to determine whether and the extent to which the distributor's distribution system is contributing to farm stray voltage measured on the farm.

4.7.4 Where the tests referred to in section 4.7.3 reveal that the distributor's distribution system is contributing more than 1 mA ACC or 0.5 V ACV to farm stray voltage on a farm, the distributor shall take such steps as may be required to ensure that such contribution does not exceed 1 mA ACC or 0.5 V ACV.

4.7.5 A distributor shall ensure that persons responsible for investigating, analyzing and determining the appropriate means of remediating farm stray voltage situations on the distributor's behalf for the purposes of meeting the distributor's obligations under this section 4.7 have competency in performing these activities. Competency may be based on recognized qualification requirements that include a training course that meets the requirements of the tasks to be performed. Services provided in relation to these activities by a person that does not have the recognized qualification requirements shall be reviewed, affirmed and documented by a person with exhibited competency.

4.7.6 A distributor serving livestock farm customers shall document, post on its web site and otherwise make available to any person on request, and file with the Board upon request, a farm stray voltage customer response procedure that describes the steps involved in the distributor's response to farm stray voltage complaints and inquiries. At a minimum, the customer response procedure must indicate:

a) how and to whom farm stray voltage complaints and inquiries should be made by livestock farm customers;
b) the types of information required by the distributor regarding the basis of the livestock farm customer's concern that ACC/ACV from the distributor's system is affecting farm operations; and
c) the estimated amount of time the distributor requires following receipt of a complaint or inquiry to contact the livestock farm customer for the purpose of scheduling a site visit for the purpose of initiating an investigation where an investigation is required.

4.7.7 A distributor shall record, retain for a period of five years and provide to the Board, on request and in the form and manner required by the Board, the following information:

a) the name and contact information of each livestock farm customer that submits a farm stray voltage complaint to the distributor, the date of the complaint and the date on which the matter was considered closed by the distributor; and
b) for each farm stray voltage investigation initiated by the distributor:
   - site information for the livestock farm customer's farm, including location; the identity and design characteristics of the circuit(s) supplying the site; and distance of the site from the circuit substation and from the end of the circuit;
   - an investigation report prepared in accordance with Appendix H, together with all other documentation required by Appendix H to be prepared; and
   - identified ACC or ACV source(s) and distribution system contribution levels; any remediation measures taken; and the total cost of the investigation and of any remediation measures taken.

4.7.8 A distributor serving livestock farm customers shall, not less than annually, provide written notice to all livestock farm customers in its service area describing how they can obtain the following from the distributor:

a) information on what farm stray voltage is, what causes it, and common ways of addressing distribution system contributions to it;

b) a copy of the distributor's farm stray voltage customer response procedure referred to in section 4.7.6; and

c) a copy of the distributor's dispute resolution process set out in its Conditions of Service.

Such notice may be given by including an insert with at least one bill submitted to livestock farm customers or by any other means as may reasonably be expected to bring the information to the attention of livestock farm customers. Posting of the information or of notice of the availability of the information on the distributor's website alone shall not constitute sufficient written notice for the purposes of this section.

5 METERING

5.1 Provision of Meters and Metering Services

5.1.1 A distributor shall provide, install and maintain a meter installation for retail settlement and billing purposes for each customer connected to the distributor's distribution system, subject to section 5.2.3.

5.1.2 A distributor may install a demand meter or interval meter for purposes of measuring demand in order to assign the customer to a rate class or to set the appropriate distribution services rate for that customer.

5.1.3 As of the date this Code comes into force a distributor shall have six months to provide a MIST meter installation for any existing customer that has an average monthly peak demand during a calendar year of over 1 MW. A distributor shall install a MIST meter on any new installation that is forecast by the distributor to have a monthly average peak demand during a calendar year of over 500 kW, for the purposes of measuring energy delivered to the customer.

5.1.4 A distributor may set a threshold level for installation of MIST meters other than that required by section 5.1.3. as long as the threshold is delineated by customer class in the distributor's Conditions of Service and sets a threshold lower than that required by section 5.1.3.

5.1.5 A distributor shall provide an interval meter within a reasonable period of time to any customer who submits to it a written request for such meter installation, either directly or through an authorized party, in accordance with the Retail Settlement Code, subject to the following conditions:

- The customer that requests interval metering shall compensate a distributor for all incremental costs associated with that meter, including the capital cost of the interval meter, installation costs associated with the interval meter, ongoing maintenance (including allowance for meter failure), verification and reverification of the meter, installation and ongoing provision of communication line or communication link with the customer's meter, and cost of metering made redundant by the customer requesting interval metering.
- The distributor shall determine whether the meter will be a MIST or MOST meter, subject to the requirements of this Code.
- A communication system utilized for MIST meters shall be in accordance with the distributor's requirements.
- A communication line shall be required in the case of inside or restricted access meters.

5.1.6 A distributor shall identify in its Conditions of Service the type of meters that are available to a customer, the process by which a customer may obtain such meters and the types of charges that would be levied on a customer for each meter type.

5.1.7 For the purposes of sections 5.1.2 to 5.1.5 inclusive, a smart meter and unit smart meter is not an interval meter.

5.1.8 Section 5.1.7 ceases to have effect in relation to a distributor on the date determined for that purpose by the Board.

5.1.9 When requested to do so by a master consumer, a distributor shall install unit smart meters that meet the specifications prescribed by Ontario Regulation 389/10.

5.2 Metering Requirements for Generating Facilities

5.2.1 A distributor shall require that an embedded retail generator whose embedded generation facility has a gross name-plate capacity of more than 10 MW install a four-quadrant interval meter. A distributor shall require that a net metered generator (as defined in section 6.7.1) and an embedded retail generator whose embedded generation facility has a gross name-plate capacity of 10 MW or less install such metering as may reasonably be required having regard to:

a. the meter data requirements necessary to enable the distributor to settle amounts owing to or from the embedded retail generator; and
b. the type of generation facility or generation technology of the embedded generation facility.

5.2.2 A distributor shall meter a customer with an embedded generation facility, other than an embedded retail generator or a net metered generator (as defined in section 6.7.1), in the same manner as the distributor's other load customers.

5.2.3 A distributor shall require that a customer with an embedded generation facility connected to the distributor's distribution system install its own meter in accordance with the distributor's metering requirements and provide the distributor with the technical details of the metering installation.

5.2.4 Where practical, metering for an embedded generation facility shall be installed at the point of supply. If it is not practical to install the meter at the point of supply, a distributor shall apply loss factors to the generation output in accordance with the loss factors applied for retail settlements and billing.

5.3 VEE Process

5.3.1 Metering data collected by a distributor shall be subjected to a validating, estimating and editing ("VEE") process if it is to be used for settlement and billing purposes.

5.3.2 A distributor shall establish a VEE process according to local practice that is fair and reasonable and provides assurance that correct data is submitted to the settlement process. The VEE process shall do the following:

- Convert raw metering data into validated, corrected or estimated "settlement-ready" metering data suitable for use in determining settlement amounts in accordance with the settlement schedule in the Retail Settlement Code.
- Detect errors in metering data introduced as a result of improper operational conditions and/or hardware/software malfunctions, including failures of or errors in metering or communication hardware, and metering data exceeding pre-defined variances or tolerances.

- Use operational system data, including historical generation and load patterns and data collected by the distributor, as appropriate, for validating raw metering data, and for editing, estimating and correcting metering data found to be erroneous or missing.

5.3.3 A distributor's VEE process for data from non-interval and MOST meters shall compare energy and demand (if applicable) readings from at least one equivalent historical billing period. A distributor shall determine the appropriate bandwidths by customer class and specify other criteria used in the VEE process.

5.3.4 A distributor's VEE process for data from MIST meters shall consider industry standards specified by the IESO in its VEE process for registered wholesale meters.

5.3.5 A distributor shall document and make available its VEE process and criteria, and allow scrutiny of its process by customers, retailers, the Board and Measurement Canada.

5.3.6 A distributor shall comply with Measurement Canada standards as a minimum metering installation and measurement standard, and may apply any other practices that exceed those standards.

5.3.7 A distributor shall have an inspection program for complex [polyphase] metering installations and document the inspection and results of the inspection.

5.3.8 Where an embedded generation facility metering installation does not conform to Measurement Canada standards or the accuracy class of instrument transformers cannot be confirmed, a distributor shall require the embedded generation facility to have the metering installation, including instrument transformers, tested, and apply a Measurement Canada correction factor to meter readings until such time as standards conformance is achieved.

5.3.9 A distributor shall ensure that persons involved in metering services have competency in performing these services. Competency may be based on recognized qualification requirements that include a training course that meets the requirements of the tasks to be performed. Metering services provided by a person that does not have the recognized qualification requirements shall be reviewed, affirmed and documented by a person with exhibited competency.

5.3.10 A distributor that provides metering services directly or through a Meter Service Provider shall exercise appropriate diligence in detecting and acting upon instances of tampering with metering and service entrance equipment. Upon identification of possible meter tampering, the distributor should notify, as appropriate, Measurement Canada, police officials, the Electrical Safety Authority, or other entities.

5.3.11 Nothing in this Code shall affect the obligation of a distributor to comply with all Measurement Canada requirements provided that, where this Code or other conditions of licence prescribe a higher standard than that prescribed in those requirements, the distributor shall comply with the higher standard.

5.3.12 A distributor shall respond to customer and retailer metering disputes, and shall establish a fair and reasonable charge for costs associated with resolution of these disputes. If the complaint is substantiated, the charge shall not be applied. In resolving the dispute, a distributor may use a qualified, independent organization at anytime during the dispute resolution process.

5.3.13 Notwithstanding any other provision of section 5.3, the VEE process for all data from a smart meter or unit smart meter shall be completed by one or more of:

a. the Smart Metering Entity;
b. the IESO, in its capacity, given by regulation, to plan, manage and implement the smart metering initiative or any aspect of that initiative; or
c. the distributor,

as may be provided by, and in accordance with, the VEE process established by the Smart Metering Entity or the IESO.

5.4 Agreement with SME or IESO Relating to Metering

5.4.1 A distributor shall, upon being requested to do so, enter into an agreement with the Smart Metering Entity or the IESO, in a form approved by the Board, which sets out the respective roles and responsibilities of the distributor and the Smart Metering Entity or the IESO in relation to metering and the information required to be exchanged to allow for the conduct of these respective roles and responsibilities.

6 DISTRIBUTORS' RESPONSIBILITIES

6.1 Responsibilities to Load Customers

This section applies to load customers other than customers with existing or proposed embedded generation facilities that are not emergency backup generation facilities, and embedded distributors.

6.1.1 A distributor shall make every reasonable effort to respond promptly to a customer's request for connection. In any event a distributor shall respond to a customer's written request for a customer connection within 15 calendar days. A distributor shall make an offer to connect within 60 calendar days of receipt of the written request, unless other necessary information is required from the load customer before the offer can be made.

6.1.2 A distributor has an implied contract with any customer that is connected to the distributor's distribution system and receives distribution services from the distributor. The terms of the implied contract are embedded in the distributor's Conditions of Service, the Rate Handbook, the distributor's rate schedules, the Distributor's licence and the Distribution System Code.

6.1.2.1 Nothing in section 6.1.2 shall be construed as permitting a distributor to recover or to seek to recover charges for a service provided to a property from any person other than a person that has agreed to be the customer of the distributor in relation to the property or that has agreed to assume responsibility for those charges.

6.1.2.2 For the purposes of section 6.1.2.1, the agreement may be in electronic form pursuant to the *Electronic Commerce Act, 2000*, and includes telephone communications provided that a recording of the telephone communication is retained by the distributor for 24 months thereafter.

6.1.2.3 Section 6.1.2.1 applies to all agreements entered into after the effective date of these amendments and is not intended to void or cancel any binding agreements for service existing as of the effective date of these amendments.

6.1.3 A distributor may require a customer to enter into a Connection Agreement with the distributor if the distributor believes that the customer has characteristics that require an explicit document to describe the relationship between the distributor and the customer. Suggested information to be included in the Connection Agreement with customers is listed in Appendix D.

6.1.4 A distributor shall enter into a Connection Agreement with a customer that is connected to the distributor's distribution system and is a wholesale market participant.

6.1.5 Before entering a property to carry out an activity described in section 40 of the *Electricity Act,* the person shall, in accordance with subsection 40(8) of the *Electricity Act:*

- provide reasonable notice of the entry to the occupier of the property;
- in so far as is practicable, restore the property to its original condition; and
- provide compensation for any damages caused by the entry that cannot be repaired.

6.2 Responsibilities to Generators

6.2.1 Section 6.2 does not apply to the connection or operation of an emergency backup generation facility or an embedded generation facility that is used exclusively for load displacement purposes at all times.

6.2.2 A distributor shall enter into a Connection Agreement with all existing generators who have a generation facility connected to the distributor's distribution system and prior to connecting a new generation facility. Where a distributor does not have a Connection Agreement with an existing generator that has a generation facility connected to the distributor's distribution system, the distributor shall be deemed to have an implied contract with the generator. The terms of the implied contract are embedded in the distributor's Conditions of Service, the Rate Handbook, the distributor's rate schedules, the distributor's licence and the Distribution System Code.

Connection Process

6.2.3 A distributor shall promptly make available a generation connection information package (the "package") to any person who requests this package. The package shall contain the following information:

a. the process for having a generation facility connected to the distributor's distribution system, including any form necessary for applying to the distributor;

b. information regarding any approvals from the ESA, the IESO, OEB, or a transmitter that are required before the distributor will connect a generation facility to its distribution system;

c. the technical requirements for being connected to the distributor's distribution system including the distributor's feeder and substation technical capacity limits as well as metering requirements;

d. the standard contractual terms and conditions for being connected to the distributor's distribution system; and

e. the name, telephone number and e-mail address of the distributor's representative for inquiries relating to the connection of embedded generation facilities.

6.2.4 Subject to all applicable laws, a distributor shall make all reasonable efforts in accordance with the provisions of section 6.2 to promptly connect to its distribution system a generation facility which is the subject of an application for connection.

6.2.4.1 Subject to section 6.2.4.2, a distributor shall establish and maintain a capacity allocation process under which the distributor will process applications for the connection of embedded generation facilities. The capacity allocation process shall meet the following requirements:

a. each application for connection, including an application under section 6.2.25a, will be allocated capacity only upon completion of the distributor's connection impact assessment, any required host distributor's connection impact assessment, and any required review of TS supply capability for the embedded generation facility;

b. a connection impact assessment will not be completed for a proposed connection that can not be completed within the feeder and/or substation technical capacity limits of the distributor's distribution system, any host distributor's distribution system or the supply TS and transmission system, including capacity additions contained in any Board approved plans to increase the capacity of one or more of the distributor's distribution system, any host distributor's distribution system or the supply TS and transmission system;

c. a connection impact assessment will not be completed unless the embedded generation facility which is the subject of the application meets the following requirements at the time the application is made:
   - demonstrated site control over the land on which the embedded generation facility is proposed to be located and any required adjacent or buffer lands in the form of property ownership (deed), long term lease (lease agreement) or an executed option to purchase or lease the land.
   - a proposed in-service date for the embedded generation facility which is no later than 5 years for water power projects or 3 years for all other types of projects from the initial date of application for connection or in accordance with the timelines in an executed OPA contract.

d. the distributor shall notify the applicant when its capacity allocation is granted;

e. an applicant shall have its capacity allocation removed if:
   i. a connection cost agreement has not been signed in relation to the connection of the embedded generation facility within 6 months of the date on which the applicant received a capacity allocation for the proposed embedded generation facility;
   ii. a new connection impact assessment is prepared for a proposed embedded generation facility under section 6.2.15 and the new assessment differs in a material respect from the original connection impact assessment prepared for that facility;
   iii. any required deposits payable to the distributor pursuant to section 6.2.18A, 6.2.18B, or 6.2.18C have not been received by the date specified by the distributor;
   iv. the distributor is informed by the OPA that the applicant has defaulted on an executed OPA contract; or
   v. the applicant defaults on an executed connection cost agreement and fails to correct the default within 30 calendar days.

f. If any applicant has its capacity allocation removed in accordance with paragraph (e), the amount of any capacity allocation deposit and or additional capacity allocation deposit paid pursuant to the connection cost agreement requirements in section 6.2.18 shall be forfeited by the applicant and retained by the distributor in a deferral account for disposition by the Board. The amount of any unspent connection cost deposit shall be returned to the applicant in accordance with the requirements of section 6.2.18 G.

g. the distributor shall provide the applicant with two months' advance notice of the expiry of the 6-month period referred to in paragraph e prior to removing the capacity allocated to the applicant.

6.2.4.2 Section 6.2.4.1 does not apply to an application to connect a micro-embedded generation facility, a capacity allocation exempt small embedded generation facility, or an embedded generation facility that is not an embedded retail generation facility. Applications to connect to which the capacity allocation process does not apply, including by virtue of section 6.2.1, shall be processed by a distributor in accordance with this Code as and when received.

6.2.4.3 Any application to connect a capacity allocation exempt small embedded generation facility that was received by a distributor prior to the date of coming into force of this section shall be processed by the distributor in accordance with the provisions of this Code applicable to such generation facilities as though the application to connect had been received by the distributor on the date of coming into force of this section.

Connection of Micro-Generation Facilities

6.2.5 A distributor shall require a person that applies for the connection of a micro-embedded generation facility to the distributor's distribution system to provide, upon making the application, the following information:

a. the name-plate rated capacity of each unit of the proposed generation facility and the total name-plate rated capacity of the proposed generation facility at the connection point;
b. the fuel type of the proposed generation facility;
c. the type of technology to be used; and
d. the location of the proposed generation facility including address and account number with the distributor where available.

6.2.6 Where the proposed micro-embedded generation facility is located at an existing customer connection, the distributor shall, within 15 days of receiving the application, make an offer to connect or provide reasons for refusing to connect the proposed generation facility. Where the proposed micro-embedded generation facility will be located other than at an existing customer connection, the distributor shall, within 60 days of receiving the application, make an offer to connect or provide reasons for refusing to connect the proposed generation facility. In either case, the distributor shall give the applicant at least 30 days to accept the offer to connect and the distributor shall not revoke the offer to connect until this time period has expired. The distributor shall not charge for the preparation of the offer to connect.

6.2.7 The distributor shall connect the applicant's micro-embedded generation facility to its distribution system within 5 days of the applicant informing the distributor that it has received all necessary approvals, providing the distributor with a copy of the authorization to connect from the ESA, entering into a Connection Agreement in the form set out in Appendix E and paying the distributor for the connection costs, including costs for any necessary new or modified metering.

Connection of other Generation Facilities

6.2.8 Sections 6.2.9 to 6.2.20 apply to the connection to a distribution system of an embedded generation facility which is not a micro-embedded generation facility.

6.2.8A Notwithstanding any other provision of this Code, a distributor shall, for the purposes of determining the connection feasibility of a capacity allocation exempt small embedded generation facility and of determining the impact of such facility on the distributor's distribution system and on any customers of the distributor, treat any capacity associated with a generation facility that has a capacity allocation referred to in section 6.2.4.1 as available capacity.

6.2.8B Where a distributor believes that, by virtue of the operation of section 6.2.8A, the connection of a capacity allocation exempt small embedded generation facility cannot reasonably be managed by the distributor without adversely affecting the capacity allocation of a generation facility, the distributor shall promptly so notify the Board in writing. In such a case, and notwithstanding any other provision of this Code, the distributor shall not take any further steps to connect the capacity allocation exempt small embedded generation facility without further direction from the Board.

6.2.9 Where a person who is considering applying for the connection of a generation facility to the distributor's distribution system requests a preliminary meeting with the distributor and provides the required information, the distributor shall provide a time when it is available to meet with the person which is within 15 days of the person providing the required information. For the purposes of this section, the following is the required information:

a. the name-plate rated capacity of each unit of the proposed generation facility and the total name-plate rated capacity of the generation facility at the connection point;

b. the fuel type of the proposed generation facility;

c. the type of technology to be used; and

d. the proposed locations of the proposed generation facility including addresses and account numbers with the distributor where available.

6.2.9.1 Upon request, a distributor shall provide the following to a person that has requested a meeting under section 6.2.9:

a. a description of the portion of the distributor's distribution system relevant to the person's embedded generation facility, including the corresponding portions of an up-to-date system schematic map showing, at a minimum, the following:
   - major distribution and sub-transmission lines;
   - transformer and distribution stations;
   - the voltage levels used for distribution;
   - sufficient geographic references to enable the person to correlate all of the above features with a municipal road map; and
   - such other information as the Board may from time to time determine;

b. subject to section 6.2.9.4, information on voltage level, fault level and minimum/maximum feeder loadings for up to three locations in the distributor's service area; and

c. for each of the proposed locations included in the request, information about the amount of additional generation, above and beyond what is already connected and what capacity has already been allocated, that can be accommodated i) within the distributor's feeder and/or substation technical capacity limits; ii) within any host distributor's feeder and/or substation capacity limits; iii) within the transmitter's TS technical capacity limits; and iv) without exceeding the IESO's requirement for a SIA.

6.2.9.2 The distributor shall provide the information referred to in section 6.2.9.1 without charge and within the 15 days referred to in section 6.2.9.

6.2.9.3 Upon request, a distributor shall, subject to section 6.2.9.4, provide the information referred to in section 6.2.9.1(b) to a person that has requested a meeting under section 6.2.9 for one or more additional locations beyond the three required by section 6.2.9.1(b). The distributor shall use reasonable efforts to provide such information within the 15 days referred to in section 6.2.9, but shall in any event provide that information within a further 15 days. The distributor may recover from the person the reasonable costs incurred by the distributor in preparing the information for the additional locations.

6.2.9.4 A distributor may withhold information on minimum/maximum feeder loadings where the distributor believes on reasonable grounds that the disclosure of such information could be used to identify the load characteristics of an existing customer and that the loading information is therefore commercially sensitive. A distributor shall, before deciding to withhold such information, make reasonable efforts to obtain the consent of the existing customer to the disclosure of the loading information.

6.2.10 At the preliminary meeting, the distributor shall discuss the basic feasibility of the proposed connection including discussing the location of existing distribution facilities in relation to the proposed generation facility and providing an estimate of the time and costs necessary to complete the connection. The distributor shall not charge for its preparation for and attendance at the meeting.

6.2.11 A distributor shall require a person who applies for the connection of a generation facility to the distributor's distribution system to, upon making the application, pay their impact assessment costs and provide the following information:

a. evidence that the requirements set out in section 6.2.4.1(c) have been met;
b. the proposed point of common coupling with the distribution system;
c. the information set out in section 6.2.9 if this has not already been provided to the distributor;
d. a single line diagram of the proposed connection;
e. a preliminary design of the proposed interface protection; and
f. all necessary technical information required by the distributor to complete the connection impact assessment.

6.2.12 Subject to sections 6.2.4.1(b), 6.2.4.1(c) and 6.2.4.2, the distributor shall provide an applicant proposing to connect a small embedded generation facility with its assessment of the impact of the proposed generation facility, a detailed cost estimate of the proposed connection and an offer to connect within:

a. 60 days of the receipt of the application where no distribution system reinforcement or expansion is required; and

b. 90 days of the receipt of the application where a distribution system reinforcement or expansion is required.

An offer to connect made to an applicant proposing to connect a capacity allocation exempt small embedded generation facility may be revoked by the distributor if not accepted by the applicant within 60 days.

6.2.13 Subject to sections 6.2.4.1(b) and 6.2.4.1(c), the distributor shall provide its assessment of the impact of the proposed embedded generation facility within:

a. 60 days of the receipt of the application in the case of a proposal to connect a mid-sized embedded generation facility; and

b. 90 days of the receipt of the application in the case of a proposal to connect a large embedded generation facility.

6.2.14 The distributor's impact assessment shall set out the impact of the proposed embedded generation facility on the distributor's distribution system and any customers of the distributor including:

a. any voltage impacts, impacts on current loading settings and impacts on fault currents;

b. the connection feasibility;

c. the need for any line or equipment upgrades;

d. the need for transmission system protection modifications; and

e. any metering requirements.

6.2.14A The distributor shall, within 10 days of initiating a connection impact assessment study, advise in writing any transmitter or distributor whose transmission or distribution system is directly connected to the specific feeder or substation to which the proposed embedded generation facility is proposing to connect. The distributor shall include in the written communication, at a minimum, the proposed in-service date, the rated capacity and type of technology of the proposed embedded generation facility. If the distributor requires a transmitter or host distributor to complete a TS review study or connection impact assessment, the distributor shall file an application with the transmitter or host distributor for such. A distributor will also inform the transmitter or distributor in writing on an ongoing basis of any change in status of the project including removing the capacity allocation for the project, material changes in the projected in-service date of the project or placing the project in service.

6.2.15 Any material revisions to the design, planned equipment or plans for the proposed embedded generation facility and connection shall be filed with the distributor and the distributor shall prepare a new impact assessment within the relevant time period set out in section 6.2.12 or 6.2.13. If the new impact assessment differs in a material respect from the original connection impact assessment for the project, the project shall have its capacity allocation removed in accordance with the requirements of section 6.2.4.1 (e) ii.

6.2.16 In the case of an application for the connection of a mid-sized or large embedded generation facility, once the impact assessment is provided to the applicant, the distributor and the applicant have entered into an agreement on the scope of the project and the applicant has paid the distributor for the cost of preparing a detailed cost estimate of the proposed connection, the distributor shall provide the applicant with a detailed cost estimate and an offer to connect by the later of 90 days after the receipt of payment from the applicant and 30 days after the receipt of comments from a transmitter or distributor that has been advised under section 6.2.17.

6.2.17 Where a distributor is preparing a detailed cost estimate in accordance with section 6.2.16 with respect to a proposed large or mid-sized embedded generation facility, the distributor shall advise any transmitter or distributor whose transmission or distribution system is directly connected to the distributor’s distribution system that it is preparing an estimate, within 10 days of receiving payment from the applicant. Where a distributor is preparing a detailed cost estimate in accordance with section 6.2.12 with respect to a proposed small embedded generation facility, the distributor shall, where the distributor believes a system directly connected to its system may be impacted by the proposed generation facility, advise any transmitter or distributor whose transmission or distribution system is directly connected to the distributor’s distribution system that it is preparing an estimate, within 10 days of receiving payment from the applicant.

6.2.18 A distributor shall enter into a connection cost agreement with an applicant in relation to a small embedded generation facility, a mid-sized embedded generation facility or a large embedded generation facility. The connection cost agreement shall include the following:

a. a requirement that the applicant pay a connection cost deposit equal to 100% of the total estimated allocated cost of connection at the time the connection cost agreement is executed;

b. if the applicant does not have an executed OPA contract which includes a requirement for security deposits or similar payments, a requirement that the applicant pay a capacity allocation deposit equal to $20,000 per MW of capacity of the embedded generation facility at the time the connection cost agreement is executed;

c. if the applicant does not have an executed OPA contract which includes a requirement for additional security deposits or similar payments, a requirement that if fifteen (15) calendar months following the execution of the connection cost agreement the embedded generation facility is not connected to the distributor's distribution system, the applicant must pay an additional capacity allocation deposit equal to $20,000 per MW of capacity of the embedded generation facility on the first day of the sixteenth (16^{th}) calendar month following the execution of the connection cost agreement;

d. if the applicant has an executed OPA contract which includes a requirement for security deposits or similar payments, the distributor shall not require the applicant to pay a capacity allocation deposit or an additional capacity allocation deposit;

e. a requirement that the mutually agreed upon in-service date is no later than 5 years for water power projects or 3 years for all other types of projects from the initial date of application for connection or in accordance with the timelines in an executed OPA contract;

f. a requirement that the applicant complete its engineering design and provide detailed electrical drawings to the distributor at least 6 months prior to the specified in-service date or as reasonably required by the distributor;

g. any requirements relating to the applicant's acceptance of the distributor's offer to connect and the connection costs; and

h. the timing of the connection.

The distributor's offer to connect shall be attached as an appendix to and form part of the cost connection agreement. Once the applicant has entered into a connection cost agreement with the distributor and has provided the distributor with detailed engineering drawings with respect to the proposal, the distributor shall conduct a design review to ensure that the detailed engineering plans are acceptable.

6.2.18A For any proponent that executed a connection cost agreement prior to the date of coming into force of this section, but is not yet connected to the distributor's distribution system, the distributor shall notify the proponent of that embedded generation facility, within 60 days of this section coming into force, that a connection cost deposit equal to 100% of the total allocated cost of connection and a capacity allocation deposit equal to $20,000 per MW of capacity of the embedded generation facility must be paid within 60 days of the distributor's notice as a condition of the applicant maintaining its current capacity allocation.

6.2.18B For any proponent that executed a connection cost agreement prior to the date of coming into force of this section, but is not yet connected to the distributor's distribution system and for which fifteen (15) calendar months or more have elapsed since the date on which the proponent executed a connection cost agreement, the distributor shall notify the proponent of that embedded generation facility, within 60 days of this section coming into force, that an additional capacity allocation deposit equal to $20,000 per MW of capacity for the embedded generation facility must be paid within 60 days of the distributor's notice as a condition of the applicant maintaining its current capacity allocation. For clarity, this additional capacity allocation deposit is in addition to any deposit that may be required under section 6.2.18A.

6.2.18C For any proponent that was allocated capacity but that had not yet executed a connection cost agreement on or before the date of coming into force of this section for one or both of the following reasons:

a. the connection impact assessment was completed within the last 12 months,

b. an IESO System Impact Assessment ("SIA") is required and has not yet been completed,

the distributor shall notify the applicant within 60 days of the later of i) the project having been allocated capacity for a period of 12 months or ii) the SIA study being completed and its impact on the generation facility being identified, that as a condition of the applicant maintaining its current capacity allocation the applicant must execute a connection cost agreement with the distributor within 60 days of the distributor's notice.

6.2.18D Any connection cost deposit, capacity allocation deposit or additional capacity allocation deposit required to be obtained by the distributor pursuant to this Code shall be in the form of cash, letter of credit from a bank as defined in the *Bank Act*, or surety bond. The distributor shall allow the applicant to select the form of any required connection cost deposit, capacity allocation deposit and/or additional capacity allocation deposit.

6.2.18E The connection cost deposit shall be used by the distributor to pay for costs allocated to the applicant and related to the connection of the embedded generation facility to the distribution system in accordance with the terms of the relevant connection cost agreement.

6.2.18F If, following the connection of an embedded generation facility to the distributor's distribution system the distributor determines that the amount of the connection cost deposit provided by the applicant exceeded the costs allocated to the applicant and related to connecting the generation facility to the distributor's distribution system, the distributor shall at the time of connection refund to the applicant the amount by which the connection cost deposit exceeded the costs related to connecting the embedded generation facility.

6.2.18G The distributor shall, no later than 30 calendar days after the applicant has its capacity allocation removed in accordance with subsection 6.2.4.1(e), refund to the applicant the amount of any remaining connection cost deposit provided by the applicant to the distributor pursuant to a connection cost agreement, provided that if the distributor has incurred costs associated with the connection of the applicant's embedded generation facility to the distributor's distribution system in accordance with the relevant connection cost agreement, the distributor shall subtract the amount of any such incurred costs from the total connection cost deposit amount provided by the applicant prior to remitting any refund to the applicant.

6.2.18H The distributor shall refund to the applicant the amount of any capacity allocation deposit or additional capacity allocation deposit provided by the applicant to the distributor no later than 30 calendar days after the applicant connects to the distributor's distribution system.

6.2.18I Where any connection cost deposit, capacity allocation deposit or additional capacity allocation deposit is provided by an applicant to a distributor in the form of cash and where the distributor refunds all or any portion of such connection cost deposit, capacity allocation deposit or additional capacity allocation deposit to the applicant in accordance with this Code, the return of such deposit or deposits shall be in accordance with the following conditions:

a. interest shall accrue monthly on the deposit amounts commencing on the receipt of the deposit required by the distributor; and

b. the interest rate shall be at the Prime Business Rate set by the Bank of Canada less 2 percent.

6.2.19 The distributor shall have the right to witness the commissioning and testing of the connection of the generation facility to the distributor's distribution system.

6.2.20 Once the applicant informs the distributor that it has received all necessary approvals, provides the distributor with a copy of the authorization to connect from the ESA and enters into the Connection Agreement, the distributor shall act promptly to connect the generation facility to its distribution system.

6.2.21 Subject to any delays in commissioning and testing of the generation facility which are beyond the control of the distributor, a distributor shall connect a proposed small embedded generation facility within:

a. 60 days of the applicant taking the steps set out in section 6.2.20, where no distribution system reinforcement or expansion is required; and

b. 180 days of the applicant taking the steps set out in section 6.2.20, where a distribution system reinforcement or expansion is required.

6.2.22 A Connection Agreement for a small, mid-sized or large embedded generation facility shall be in the form set out in Appendix E where a standard form of contract is set out in Appendix E for that size of embedded generation facility.

6.2.23 Material on the process for connecting a generation facility to a distribution system is set out in Appendix F.1. This material is for information purposes only and the provisions of the Code govern in the case of any conflict.

6.2.24 A distributor may by written agreement with an applicant who is proposing to connect a small, mid-sized or large embedded generation facility provide that the process for connecting the generation facility to be followed is the process set out for a smaller category of embedded generation facility, including a micro-embedded generation facility.

6.2.25a A distributor shall require a generator that proposes to increase the output of an embedded generation facility that is then in service to submit a new application to connect, and the provisions of sections 6.2.9 to 6.2.24 shall apply.

Technical Requirements

6.2.25 A distributor shall ensure that the safety, reliability and efficiency of the distribution system is not materially adversely affected by the connection of a generation facility to the distribution system. A distributor shall require that new or significantly modified generation facilities meet the technical requirements specified in Appendix F.2.

6.2.26 A distributor shall ensure that the distribution system is adequately protected from potential damage or increased operating costs resulting from the connection of a generation facility. Despite section 2.2.1, if damage to the distribution system or increased operating costs result from the connection of a generation facility other than a micro-embedded generation facility, the distributor shall be reimbursed for these costs by the generator.

6.2.27 A distributor shall require that a generator with a generation facility connected to the distributor's distribution system has a regular, scheduled maintenance plan to ensure that the generator's connection devices, protection systems and control systems are maintained in good working order. This requirement will be provided for in the connection agreement.

6.2.28 All equipment that is connected, operating or procured or ordered before May 1, 2002 is deemed to be in compliance with the technical requirements of this code.

6.2.29 A distributor may require that equipment deemed compliant under section 6.2.28 be brought into actual compliance with the technical requirements of this code within a specific reasonable time period where there is:

a. a material deterioration of the reliability of the distribution system resulting from the performance of the generator's equipment;

b. a material negative impact on the quality of power of an existing or a new customer resulting from the performance of the generator's equipment; or

c. a material increase in generator capacity at the site where the equipment deemed compliant is located.

6.2.30 The distributor may act in accordance with section 6.2.29, once the distributor has developed rules and procedures for requiring equipment to be brought into actual compliance and these rules and procedures have been provided to the generator.

6.2A Connection Process for Distributor-owned Generation Facilities

6.2A.1 Except as otherwise provided in sections 6.2A.2 to 6.2A.6, a distributor shall connect a generation facility that will be owned by it in accordance with section 6.2.

6.2A.2 The following sections do not apply in respect of the connection of a generation facility that will be owned by the distributor to whose distribution system the facility is being connected: 6.2.3; 6.2.4.1(d); 6.2.4.1(g); 6.2.5; 6.2.9; 6.2.9.1; 6.2.9.2

6.2A.3 In applying section 6.2 in relation to a generation facility that will be owned by the distributor to whose distribution system the generation facility will be connected, the following shall apply:

(a) the distributor shall be deemed to be and shall in all respects be treated as the "applicant" or person applying for the connection of a generation facility (however that may be expressed in section 6.2);

(b) where a provision in section 6.2 requires an applicant or generator to pay a cost, charge, fee or other amount of money or requires a distributor to refund or return a cost, charge, fee or other amount of money to an applicant or a generator, the distributor shall instead record the relevant amount in accordance with the Accounting Guidelines. The payment requirement shall be deemed to have been satisfied on the date on which the requisite accounting record is made by the distributor;

(c) where a provision in section 6.2 requires an applicant or generator to provide a deposit or requires a distributor to refund or return all or part of a deposit to an applicant or a generator, the distributor shall instead record the relevant amount in accordance with the Accounting Guidelines. The requirement to provide, refund or return a deposit shall be deemed to have been satisfied on the date on which the requisite accounting record is made by the distributor;

(d) the distributor shall complete its standard connection application form applicable to the type and size of its generation facility, and shall append to that form any information that would be required to be provided by a third party applicant under section 6.2.5 or 6.2.9, as applicable, and section 6.2.11, if that information is not already covered by the standard application. This completed form shall be deemed to be and shall in all respects be treated as the application to connect (however that may be expressed in section 6.2); and

(e) the date on which an application is filed with the Ontario Power Authority for a contract under the Feed-in Tariff program in relation to the output of the distributor's generation facility shall be deemed to be and shall in all respects be treated as the date of receipt by the distributor of the application to connect its generation facility, and the distributor shall date stamp the application form referred to in section paragraph (d) accordingly.

For the purposes of this section: (i) "deposit" means a capacity allocation deposit, an additional capacity allocation deposit and a connection cost deposit, as applicable; and (ii) "Accounting Guidelines" means all requirements established by the Board and in effect at the relevant time in respect of the accounting records, accounting principles and accounting separation standards to be followed by the distributor in relation to a generation facility owned by the distributor, including the "Guidelines: Regulatory and Accounting Treatments for Distributor-Owned Generation Facilities" (G-2009-0300).

6.2A.4 The following shall apply in relation to the connection of a generation facility that will be owned by the distributor to whose distribution system the generation facility will be connected:

(a) where capacity can be allocated in respect of the generation facility in accordance with the applicable provisions of section 6.2, capacity shall be allocated in relation to the generation facility within 150 days from the deemed date of receipt of the application, determined in accordance with section 6.2A.3(e). The distributor shall document the date on which capacity has been allocated in relation to the generation facility;

(b) in lieu of the requirement set out in section 6.2.4.1(e)(v), capacity allocated in respect of the generation facility shall be removed if the distributor or the generation facility fail to satisfy any of the requirements of a connection cost agreement referred to in section 6.2A.4(i);

(c) in lieu of section 6.2.6, the following shall apply:

i. the distributor shall complete its standard offer to connect applicable to micro-embedded generation facilities in relation to its generation facility within the applicable timeline set out in section 6.2.6; and

ii. the distributor shall ensure that all applicable requirements of that standard offer to connect are met by or in relation to its generation facility;

(d) in lieu of section 6.2.7, the following shall apply:

i. the distributor shall document the receipt of all of the necessary approvals or the authorization to connect referred to in section 6.2.7;

ii. in lieu of the requirement to enter into a Connection Agreement, the distributor shall ensure that all applicable requirements of the Connection Agreement are met by or in relation to its generation facility; and

iii. subject to paragraph (ii), the distributor shall connect its generation facility to its distribution system within 5 days of the receipt of last necessary approval or authorization referred to in section 6.2.7;

(e) in lieu of section 6.2.12, the following shall apply:

i. the distributor shall complete an assessment of the impact of its generation facility and a detailed cost estimate of the proposed connection within the applicable timeline set out in section 6.2.12;

ii. the distributor shall complete its standard offer to connect applicable to the type and size of its generation facility within the applicable timeline set out in section 6.2.6;

iii. the distributor shall ensure that all applicable requirements set out in its standard offer to connect are met by or in relation to its generation facility; and

iv. in lieu of the permission to revoke the standard offer to connect, if the distributor has not satisfied the obligation to provide any required deposits (as defined in section 6.2A.3) in the manner specified in section 6.2A.3(b) within 60 days of the date on which the distributor completes the standard offer to connect, the distributor shall terminate the connection process in relation to its generation facility and the capacity allocated to that facility shall be removed. The distributor shall not thereafter connect the generation facility except further to the preparation of a new application for connection as set out in section 6.2A.3(d);

(f) in lieu of section 6.2.13, the distributor shall complete an assessment of the impact of its generation facility within the applicable timeline set out in section 6.2.13;

(g) in lieu of section 6.2.15, where a material revision to the design, planned equipment or plans for its generation facility is proposed by the distributor, the distributor shall document the details of such revision;

(h) in lieu of section 6.2.16, the following shall apply:

  i. the distributor shall complete a detailed cost estimate of the proposed connection within the timeline set out in section 6.2.16;

  ii. the distributor shall complete its standard offer to connect applicable to the type and size of its generation facility within the applicable timeline set out in section 6.2.16; and

  iii. the distributor shall ensure that all applicable requirements set out in its standard offer to connect are met by or in relation to its generation facility;

(i) in lieu of section 6.2.18, the following shall apply:

  i. the distributor shall ensure that all of the requirements that must be included in a connection cost agreement as set out in section 6.2.18, other than in section 6.2.18 (g), as well as all other applicable requirements contained in the distributor's standard connection cost agreement applicable to the type and size of its generation facility are met by or in relation to its generation facility; and

  ii. for the purposes of paragraph (i), the timelines expressed in section 6.2.18(c) by reference to the execution of a connection cost agreement shall instead be calculated by reference to the date that is 150 days from the date of deemed receipt of the application to connect, determined in accordance with section 6.2A.3(e);

(j) in lieu of section 6.2.20, the following shall apply:

  i. the distributor shall document the receipt of all of the necessary approvals and of the authorization to connect referred to in section 6.2.20;

  ii. in lieu of the requirement to enter into a Connection Agreement, the distributor shall ensure that all applicable requirements set out in the applicable form of Connection Agreement are met by or in relation to its generation facility; and

  iii. subject to paragraph (ii), the distributor shall promptly connect its generation facility to its distribution system following receipt of the last necessary approval or authorization referred to in section 6.2.20;

(k) for the purposes of section 6.2.21, the timelines expressed in that section shall be calculated from the date of receipt of the last necessary approval or authorization referred to in section 6.2.20;

(l) a distributor may elect to connect its generation facility using a process for connecting a smaller category of embedded generation facility as set out in section 6.2.24 only if the distributor also makes this option available to third party applicants as set out in the distributor's Conditions of Service, and only on the same terms and conditions; and

(m) in lieu of section 6.2.25a, where a distributor proposes to increase the output of its generation facility that is then in service, the distributor shall complete a new standard connection application in the form applicable to the type and size of its generation facility as set out in section 6.2A.3(d) and, subject to section 6.2A.2, sections 6.2.12 to 6.2.24 shall apply.

6.2A.5 Where any provision of section 6.2A requires a distributor to ensure that all applicable requirements of a standard offer to connect or of an agreement are met, a senior officer of the distributor shall certify such compliance in writing. Such certification shall be completed in respect of each such requirement at the time at which the distributor has taken the necessary steps to confirm that the requirement has been met.

6.2A.6 Where any provision of section 6.2A requires a distributor to document information or to complete a document, the distributor shall retain the document until two years after the date on which the connection process is terminated in respect of its generation facility or the date on which its generation facility ceases to be connected to its distribution system.

6.3 Responsibilities to Other Distributors

6.3.1 A distributor shall make every reasonable effort to respond promptly to another distributor's request for connection. A distributor shall provide an initial consultation with another distributor regarding the connection process within thirty (30) days of receiving a written request for connection. A final offer to connect the distributor to the host distributor's distribution system shall be made within ninety (90) days of receiving the written request for connection, unless other necessary information outside the distributor's control is required before the offer can be made.

6.3.2 A distributor shall make a good faith effort to enter into a Connection Agreement with a distributor connected to the distributor's distribution system. The contents and format of the Connection Agreement are in the discretion of the distributors that participate in the Connection Agreement but must conform to the requirements of this Code. Appendix G provides an example of the process that distributors should follow in providing a connection to another distributor.

6.3.3 The reliability of supply and the voltage level at the delivery point from a host distributor's distribution system to an embedded distributor's distribution system shall be as good as or better than what is provided to the host distributor's other distribution customers.

6.3.4 A distributor shall not build any part of its distribution system in another distributor's licensed service area except under the following conditions:

- The part of the distribution system that is to be located inside another licensed service area is dedicated to the delivery of electricity to the distributor who owns the distribution facilities; and
- There is no apparent opportunity for both distributors to share the distribution facilities; and
- The distributor in whose service area the distribution facilities are to be located determines that the presence of the distribution facilities in that location does not impinge on its distribution operations.

6.3.5 A distributor that owns equipment in another distributor's licensed service area shall allow that distributor access to the equipment for the following reasons:

- Emergencies.
- When the equipment may cause a violation of a licence condition by the distributor who is licensed for the service area.
- Upon a reasonable request by the distributor who is licensed for the service area.
- In accordance with any arrangement between the two distributors.

6.4 Sharing Arrangements Between Distributors

6.4.1 A distributor that owns distribution facilities in another distributor's licensed service area, and decides to share those distribution facilities with the distributor licensed to serve the service area, shall have an agreement that describes the terms of the sharing arrangement with the other distributor.

6.4.2 An operating agreement for multiple ownership circuits shall include, among other conditions, clauses that require that:

- Each section owner provide downstream owners with fault current information and protection settings of upstream protective devices.
- Each section owner provide upstream owners with load forecasting information.
- Each section owner maintain phase balance within generally acceptable industry standards.
- Each section owner ensure generally acceptable industry standards pertaining to power quality and voltage levels are adhered to on the section owner's portion of the feeder.
- The owner of the feeder breaker be responsible for maintaining appropriate relay settings for overall feeder protection.
- Each distributor be responsible to provide the required information to accomplish appropriate relay settings for overall feeder protection, including information on feeder characteristics and loading information.

6.4.3 In existing or new multiple ownership circuits, a distributor shall be responsible for maintenance, protection and power quality of the distributor's own portion of the shared feeder. The distributor shall ensure that its portion of the feeder has proper fault protection and voltage within proper limits. This generally would require the owner of each section of the feeder to provide for suitable overcurrent protection devices and voltage regulators, as appropriate, at the upstream boundary and suitable metering, if not already available for settlement purposes, at the downstream boundary.

6.5 Load Transfers

6.5.1 A distributor (referred to in this section as the geographic distributor) that provides distribution services through a load transfer may continue to do so under the following conditions:

- The load transfer customer enters into a Connection Agreement or is deemed to have an implied contract with the geographic distributor and interacts only with the geographic distributor.
- The geographic distributor provides service to the load transfer customer in accordance with its Conditions of Service and bills the load transfer customer in accordance with its regulated charges and rates.
- The geographic distributor is responsible for system reliability or equipment failures associated with the distribution system equipment it owns or operates that is used to deliver electricity to the load transfer customer.
- The geographic distributor allows the distributor that owns the connection assets (referred to as the physical distributor) access to the distribution equipment used to service the load transfer customer, as required for system reliability and safety.
- The geographic distributor is responsible to the physical distributor for all charges and costs incurred by the load transfer customer for all costs defined in Retail Settlement Code, including distribution costs, competitive electricity costs and non-competitive electricity costs provided to the customer through the physical distributor's distribution system.
- The geographic distributor is responsible for facilitating the load transfer customer's access to retail competition and shall interact with any competitive retailer chosen by the customer.

6.5.2 A physical distributor that provides distribution services through a load transfer may continue to do so under the following conditions:

- The physical distributor refers the load transfer customer or a retailer that intends to service the load transfer customer to the geographic distributor for all issues. The geographic distributor is responsible to work with the physical distributor on any issues that are the direct responsibility of the physical distributor.
- The physical distributor is responsible for system reliability or equipment failures associated with the distribution system equipment it owns or operates that is used to deliver electricity to the load transfer customer.
- The physical distributor allows the geographic distributor access to its equipment, as required for system reliability and safety.

6.5.3 During the period between May 1, 2002 and June 30, 2014, a physical distributor shall be obligated to continue to service an existing load transfer customer unless otherwise negotiated between the physical distributor and geographic distributor.

6.5.4 During the period between May 1, 2002 and June 30, 2014, a geographic distributor that services a load transfer customer shall either:

a. negotiate with a physical distributor that provides load transfer services so that the physical distributor will be responsible for providing distribution services to the customer directly, including application for changes to the licensed service areas of each distributor; or

b. expand the geographic distributor's distribution system to connect the load transfer customer and service that customer directly.

Once a load transfer customer enters into a Connection Agreement or implied contract with the physical distributor, the physical distributor shall have sole responsibility for that customer.

6.5.4.1 A geographic distributor shall file with the Board, by November 30, 2010, an updated implementation plan for eliminating its existing load transfer arrangements. The updated implementation plan shall:

a. summarize the geographic distributor's existing load transfer arrangements;

b. set out the geographic distributor's proposed method for eliminating each load transfer arrangement; and

c. set out the geographic distributor's proposed timeline for eliminating each load transfer arrangement.

6.5.4.2 A geographic distributor shall file an annual status report with the Board by November 30 of each year, starting in 2011 and ending in 2013, that summarizes the geographic distributor's progress in relation to its updated implementation plan. The annual status report shall also include a summary of the geographic distributor's load transfer arrangements that have been eliminated within the year, the method of elimination, and the date they were eliminated.

6.5.5 A distributor may enter into a new load transfer agreement with another distributor with leave of the Board.

6.6 Provision of Information

6.6.1 A distributor shall communicate general market and educational information to consumers connected to its distribution system as required by the Board.

6.6.2 A distributor shall inform a person about the person's obligations to the distributor, and shall monitor and require compliance to ensure that the person is meeting its obligations. A distributor shall inform the consumer or customer about the distributor's rights to disconnect service.

6.6.3 At the request of a consumer, a distributor shall provide a list of retailers who have Service Agreements in effect with the distributor. The list shall conform to the requirements of section 2.5 of the Affiliate Relationships Code. The list should inform the consumer that an alternative retailer does not have to be chosen in order to ensure that the consumer receives electricity and the terms of service that are available under Standard Supply Service.

6.6.4 A distributor shall not provide information on products retailed by a retailer.

6.6.5 Upon receiving an inquiry from a consumer connected to its distribution system, the distributor shall either respond to the inquiry if it deals with the distributor's distribution services or provide the consumer with contact information for the entity responsible for the item of inquiry, in accordance with chapter 7 of the Retail Settlement Code.

6.6.6 An embedded distributor that receives electricity from a host distributor shall provide load forecasts or any other information related to the embedded distributor's system load to the host distributor, as determined and required by the host distributor. A distributor shall not require any information from another distributor unless it is required for the safe and reliable operation of either distributor's distribution system or to meet a distributor's licence obligations.

6.7 Net Metered Generators

6.7.1 In this section 6.7:

- "eligible generator" in respect of a distributor means a customer of a distributor that meets the criteria set out in section 7(1) of the Net Metering Regulation;
- "net metered generator" means an eligible generator to whom net metering has been made available by a distributor; and
- "Net Metering Regulation" means the Net Metering Regulation, O. Reg. 541/05.

6.7.2 A distributor shall, upon request, make net metering available to eligible generators in its licensed service area in accordance with the Net Metering Regulation, on a first-come first-served basis, unless the cumulative generation capacity from net metered generators in its licensed service area equals one percent of the distributor's annual maximum peak load for the distributor's licensed service area, averaged over three years, as determined by the Board from time to time.

6.7.3 A distributor shall bill a net metered generator on a net metering basis in accordance with the Net Metering Regulation provided that the net metered generator meets the requirements of section 2(2) of the Net Metering Regulation.

6.7.4 A distributor may, upon request, make net metering available to additional eligible generators in its licensed service area and may bill them on a net metering basis when the cumulative maximum generation capacity from net metered generators in its licensed service area exceeds one percent of the distributor's annual maximum peak load for the distributor's licensed service area, averaged over three years, as referred to in section 6.7.2.

6.7.5 A distributor shall, in the manner and time specified by the Board, file with the Board the total rated maximum output capacity of generation facilities in its licensed service area to which net metering has been made available as of:

February 10, 2006; and such later dates as are determined by the Board.

7 SERVICE QUALITY REQUIREMENTS

7.1 Definitions

In this section 7, the following words have the meanings set out below.

"answered" means connected to a person that is a representative of the distributor. Connection to a voice mailbox or an answering machine, or placing a person in a queue, does not constitute answering.

"customer care telephone number" means any telephone number that is dedicated exclusively to, and given to the public by the distributor for, the purpose of contacting the distributor on matters concerning customer care, including customer account enquiries and other customer service enquiries. Where a distributor does not have a telephone number dedicated exclusively to matters concerning customer care, any telephone number given to the public for the purpose of making enquiries of the distributor shall be deemed to be a "customer care telephone number".

"emergency call" means a call where the assistance of the distributor has been requested by fire, ambulance or police services.

"qualified enquiry" means an enquiry received by a distributor from a customer or representative of a customer pertaining to the customer's existing or prospective service in which a written response is requested by the customer or representative of the customer or determined by the distributor to be necessary. A "qualified enquiry" does not include any of the following, which shall be addressed in accordance with other applicable requirements: cable locate requests; retailer Service Transaction Requests; and enquiries of a general nature not relating specifically to service currently provided to a customer or to a new service being requested by a customer.

"qualified incoming calls" means calls that are received during the regular hours of operation of a distributor's customer call centre and are either:

(a) telephone calls for which the customer normally reaches a customer service representative directly or has been transferred to a customer care line by a general operator; or
(b) telephone calls in which the customer has reached the distributor's Interactive Voice Response ("IVR") system and selected the option of speaking to a customer service representative.

The following are not “qualified incoming calls”:

(a) telephone calls that are abandoned by the customer prior to asking for a customer service representative; and
(b) telephone calls for which the customer elects IVR self-service.

“new service” means a connection that requires an Electric Safety Authority certificate before the connection can be completed. This includes, but is not limited to, connections associated with a service upgrade and connections that involve the installation of an additional meter on the distribution system where no meter previously existed. Solely replacing an existing meter is not a new service.

"service conditions" means any condition that must be satisfied before the service will be provided and may include the payment of connection fees, the signing of an offer to connect, the completion of a distribution system expansion, the delivery of any necessary equipment and the receipt of an electrical safety inspection certificate.

7.2 Connection of New Services

7.2.1 A connection for a new service request for a low voltage (<750 volts) service must be completed within 5 business days from the day on which all applicable service conditions are satisfied, or at such later date as agreed to by the customer and distributor.

7.2.2 A connection for a new service request for a high voltage (>750 volts) service must be completed within 10 business days from the day on which all applicable service conditions are satisfied, or at such later date as agreed to by the customer and distributor.

7.2.3 This service quality requirement must be met at least 90 percent of the time on a yearly basis.

7.3 Appointment Scheduling

7.3.1 When a customer or a representative of a customer requests an appointment with a distributor, the distributor shall schedule the appointment to take place within 5 business days of the day on which all applicable service conditions are satisfied or on such later date as may be agreed upon by the customer and distributor.

7.3.2 Where the appointment in section 7.3.1 requires the presence of the customer or the customer's representative, the distributor shall fulfil the requirements set out in section 7.4.1.

7.3.3 Where the appointment in section 7.3.1 does not require the presence of the customer or the customer's representative, the distributor shall arrive for the appointment on the day scheduled under section 7.3.1.

7.3.4 This service quality requirement must be met at least 90 percent of the time on a yearly basis.

7.3.5 All of the actions set out in:

(a) section 7.3.1; and

(b) section 7.3.2 or section 7.3.3, as applicable,

must be completed in order to fulfil this service quality requirement.

7.3.6 This service quality requirement applies regardless of whether or not the presence of the customer or the customer's representative is required.

7.3.7 This service quality requirement does not apply to appointments that are subject to the requirements in sections 7.2.1 and 7.2.2.

7.4 Appointments Met

7.4.1 When an appointment is either:

(a) requested by a customer or a representative of a customer with a distributor ; or

(b) required by a distributor with a customer or representative of a customer,

the distributor must offer to schedule the appointment during the distributor's regular hours of operation within a window of time that is no greater than 4 hours (i.e., morning, afternoon or, if available, evening). The distributor must then arrive for the appointment within the scheduled timeframe.

7.4.2 This service quality requirement must be met at least 90 percent of the time on a yearly basis.

7.4.3 Both of the actions set out in section 7.4.1 must be completed in order to fulfil this service quality requirement.

7.4.4 If the distributor arrives at the scheduled appointment within the required time period but the appointment cannot be met because the customer failed to attend the appointment, the distributor may consider the appointment to have been met for the purpose of determining its performance with the standard.

7.4.5 This service quality requirement applies to appointments that:

(a) require the presence of the customer or the customer's representative;

(b) are scheduled to occur at the distributor's office, the customer's premises, business or work site, or at another location agreed to by the distributor and customer; and

(c) are a frequently recurring part of the distributor's normal course of business, including, but not limited to, the following:

(i) disconnecting and/or reconnecting service to effect maintenance or upgrades;

(ii) connecting a new customer;

(iii) connecting a new service for an existing customer;

(iv) providing underground cable locates;

(v) inspections;

(vi) gaining access to read or replace an inside meter or to provide the customer with instructions on the proper use of a prepaid meter or similar device; and

(vii) appointments that are rescheduled as required by section 7.5.1.

7.5 Rescheduling a Missed Appointment

7.5.1 When an appointment to which sections 7.3.1, 7.3.3, or 7.4.1 apply is missed or is going to be missed, the distributor must:

(a) attempt to contact the customer before the scheduled appointment to inform the customer that the appointment will be missed; and

(b) attempt to contact the customer within one business day to reschedule the appointment.

7.5.2 This service quality requirement must be met 100 percent of the time on a yearly basis.

7.5.3 Both of the actions set out in section 7.5.1 must be completed in order to fulfil this service quality requirement.

7.5.4 This requirement does not apply if the appointment is missed due to the failure of the customer or the representative of the customer to attend the appointment.

7.5.5 The rescheduled appointment becomes a new appointment for the purposes of sections 7.3.1 or 7.4.1 as appropriate.

7.6 Telephone Accessibility

7.6.1 Qualified incoming calls to the distributor’s customer care telephone number must be answered within the 30 second time period established under section 7.6.3.

7.6.2 This service quality requirement must be met at least 65 percent of the time on a yearly basis.

7.6.3 For qualified incoming calls that are transferred from the distributor’s IVR system, the 30 seconds shall be counted from the time the customer selects to speak to a customer service representative. In all other cases, the 30 seconds shall be counted from the first ring.

7.7 Telephone Call Abandon Rate

7.7.1 The number of qualified incoming calls to a distributor’s customer care telephone number that are abandoned before they are answered shall be 10 percent or less on a yearly basis.

7.7.2 For the purposes of section 7.7.1, a qualified incoming call will only be considered abandoned if the call is abandoned after the 30 second period established under section 7.6.1 has elapsed.

7.8 Written Response to Enquires

7.8.1 A written response to a qualified enquiry shall be sent by the distributor within 10 business days.

7.8.2 This service quality requirement must be met at least 80 percent of the time on a yearly basis.

7.8.3 The 10 business days shall be counted from the date on which any conditions associated with the enquiry have been satisfied (such as the date of a move where there is a request for a final statement of account) or, if there are no such conditions, from the date of receipt of the enquiry.

7.8.4 A distributor may consider a written response to have been sent if the distributor sends a written acknowledgement of receipt of the qualified enquiry and includes a specific date in which a complete response to the qualified enquiry will be provided.

7.8.5 A written response shall be deemed to have been sent on the date on which it is faxed, mailed or e-mailed by the distributor.

7.9 Emergency Response

7.9.1 Emergency calls must be responded to within 120 minutes in rural areas and within 60 minutes in urban areas.

7.9.2 This service quality requirement must be met at least 80 percent of the time on a yearly basis.

7.9.3 The definition of “rural” and “urban” should correspond to the municipality’s definition.

7.9.4 The arrival of a qualified service person on site will constitute a response.

7.10 Reconnection Standards

7.10.1 Where a distributor has disconnected the property of a customer for non-payment, the distributor shall reconnect the property within 2 business days, as defined in section 2.6.7, of the date on which the customer:

(a) makes payment in full of the amount overdue for payment as specified in the disconnection notice; or
(b) enters into an arrears payment agreement with the distributor referred to in section 2.7.1A.

7.10.2 This service quality requirement must be met at least 85 percent of the time on a yearly basis.

OEB Distribution Reliability Standards

ONTARIO ENERGY BOARD

Staff Report to the Board

Electricity Distribution System Reliability Standards

EB-2010-0249

March 31, 2011

A. INTRODUCTION

The Ontario Energy Board (the "Board") has on a number of occasions emphasized the importance it places on system reliability as an important measure of a distributor's service quality and performance. In its March 12, 2008 Notice of Proposal to amend the Distribution System Code to establish customer service quality standards for electricity distributors, the Board reaffirmed its commitment to the establishment and codification of distribution system reliability standards. The Board's 2010-2013 Business Plan identified the development of electricity distributor system reliability standards as a key initiative.

By letter dated August 23, 2010, the Board invited interested parties to participate in a consultation process regarding the further development of regulatory requirements associated with electricity distribution system reliability. The consultation involved the review of existing practice in Ontario regarding the collection and use of system reliability performance information by distributors; the issuance of reports detailing the results of consumer and jurisdictional research conducted by consultants retained by the Board for that purpose; a stakeholder conference; and the filing of written comments on the issues discussed at the stakeholder conference.

Over 30 stakeholders participated in the stakeholder conference, and fifteen filed written comments.[1] Those written comments are available on the Board's website on the project webpage.[2]

This staff Report provides an overview of the research conducted as part of this consultation and summarizes the issues and stakeholders' views on the issues as expressed in their written comments. This Report also sets out Board staff's recommendations in relation to the subject-matter of the consultation.

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[1] Two distributors made a joint filing.

[2] The written comments and all other materials relating to this consultation are available at http://www.ontarioenergyboard.ca/OEB/Industry/Regulatory+Proceedings/Policy+Initiatives+and+Consultations/System+Reliability+Standards.

B. BACKGROUND

Distributors are currently required to monitor and report to the Board on their performance against four reliability indicators, namely:

i. a System Average Interruption Duration Index ("SAIDI"), an indicator of the length of interruptions that customers experience in a year on average (both inclusive and exclusive of loss of supply);

ii. a System Average Interruption Frequency Index ("SAIFI"), an indicator of the average number of sustained interruptions that each customer experiences (both inclusive and exclusive of loss of supply);

iii. a Customer Average Interruption Duration Index ("CAIDI"), an indicator of the speed at which power is restored (both inclusive and exclusive of loss of supply); and

iv. a Momentary Average Interruption Frequency Index ("MAIFI"), an indicator of the average number of momentary interruptions that each customer experiences.

The Board's policy pertaining to the monitoring and reporting of performance against SAIDI, SAIFI and CAIDI has been in place since 2000. The policy was initially contained in Chapter 7 of the Board's *First Generation PBR Electricity Distribution Rate Handbook,* and subsequently in Chapter 15 of its *2006 Electricity Distribution Rate Handbook*. The system reliability monitoring and reporting requirements pertaining to SAIDI, SAIFI and CAIDI are now set out in section 2.1.4.2 of the Board's *Electricity Reporting and Record Keeping Requirements* (the "RRR"). The system reliability monitoring and reporting requirements pertaining to MAIFI were added to the RRR effective May 1, 2010, although distributors that do not have the systems capability that enables them to capture or measure MAIFI are exempted from reporting on MAIFI performance. Except where otherwise noted, all subsequent references in this Report to Ontario system reliability indicators should be understood as being limited to the three historical indicators; namely, SAIDI, SAIFI and CAIDI.

Distributor performance against the system reliability indicators is reported annually in the Board's *Yearbook for Electricity Distributors*. In accordance with section 2.3.7 of Chapter 2 of the Board's *Filing Requirements for Transmission and Distribution*

Applications, distributors must include a report on their performance against system reliability indicators as part of their cost of service rate applications.

The Board's expectation in relation to performance against the system reliability indicators, as expressed in the two *Rate Handbooks*, is that a distributor with at least 3 years of data on a given index should, at minimum, remain within the range of its historical performance.

In January 2008, the Board initiated a consultation to assist in the development of a service quality regime for electricity distributors (EB-2008-0001). That consultation culminated in the codification of service quality requirements, which are now set out in the Distribution System Code.

The Board chose not to implement mandatory system reliability standards at that time, for the following reasons set out in the Board's March 12, 2008 Notice of Proposal to amend the Distribution System Code: [3]

> …the Board is of the view that the reliability data reported to the Board does not provide a true representation of a distributor's performance. Therefore, the Board is not convinced that this data is suitable to use as a basis for setting a performance standard.
>
> The Board also believes that research must be completed in order to determine the level of reliability that is appropriate; what other system reliability measures maybe be considered; the potential impact on distributor costs and rates that will result from setting a standard and the nature of any transitional measures that may be needed.

At the same time, the Board emphasized that its decision to defer the introduction of mandatory system reliability standards in no way diminished the importance that the Board places on system reliability.

[3] Notice of Proposal to Amend a Code, Proposed Amendments to Amend the Distribution System Code, March 12, 2008 (EB-2008-0001).
http://www.ontarioenergyboard.ca/OEB/Industry/Regulatory+Proceedings/Policy+Initiatives+and+Consultations/Archived+OEB+Key+Initiatives/Electricity+Service+Quality+Regulation

C. RESEARCH RESULTS

As part of this consultation, the Board retained the services of expert consultants to undertake research into the implementation of service reliability regimes in other jurisdictions, and to ascertain the views of consumers on the level of reliability they currently receive from their respective distributors.

C.1 – Jurisdictional Review

Pacific Economics Group Research, LLC ("PEG") was retained to prepare a report outlining the electricity distribution reliability regimes in place outside of Ontario. The report, "System Reliability Regulation: A Jurisdictional Survey" (the "PEG Report"), posted on the Board's website on August 23, 2010, summarizes the distribution system reliability regimes implemented in an number of other jurisdictions, including other Canadian provinces and within the United States and Europe.

The PEG Report identifies three different approaches to system reliability regulation: (i) "monitoring" regimes, where utilities are required to report on their performance on defined indicators; (ii) "target" regimes, where utilities are expected to achieve established, targeted levels of performance on defined performance indicators; and (iii) "penalty/reward" regimes, where utilities are automatically penalized, and sometimes rewarded, depending on their performance against established benchmarks, including through the operation of "performance guarantees" where the distributor must pay individual customers if certain performance standards (or benchmarks) are not met.

PEG characterizes Ontario as having "a type of service target regime". Of the 75 jurisdictions reviewed in the PEG Report, 47% use the "monitoring" approach, 17% use the "target" approach and 36% use the "penalty/reward" approach.

According to the PEG Report, 40% of the surveyed jurisdictions use the same three system reliability indicators as does Ontario, while 48% use just two of three (SAIDI and SAIFI). Only 23% of the jurisdictions surveyed use a momentary outage indicator (MAIFI), none of which are in Canada (as noted above, a requirement to monitor and report on MAIFI was introduced into the RRR effective May, 2010).

PEG's research indicates that, in jurisdictions where performance targets are used, the majority set their targets on an individual distributor basis rather than on a sector wide basis.

Other elements of system reliability that are regulated in at least some other jurisdictions but not in Ontario include:

- SAIDI and SAIFI measures that are 'normalized' to exclude severe events
- Circuit indicators
- Severe Storm/restoration indicators
- "Energy Not Supplied" indicator
- Engineering and/or econometric-based benchmarks

C.2 – Consumer Survey

An important consideration when establishing system reliability standards is the degree to which consumers are willing to pay for a certain standard of reliability. To help ascertain consumer views on this issue, the Board engaged a consultant, Pollara, to conduct two telephone surveys in the summer of 2010, which solicited the opinions of consumers from across the province regarding electricity outages and other reliability-related issues. The first survey polled 905 residential consumers. The second survey polled 301 business consumers falling into the General Service < 50kW, General Service ≥ 50kW and Large User rate classes. Reports on the results of the two surveys were posted on the Board's website on October 7, 2010.

The surveys indicate that the majority of consumers are generally satisfied with current levels of system reliability, with 89% of residential consumers and 92% of business consumers reporting that they are "somewhat satisfied" or "very satisfied" with the reliability of electricity supply. However, over 75% of respondents in both groups indicated that, despite being generally satisfied, they still believe it is important for distributors to continue to work to reduce the number of outages.

Based on the Pollara survey results, most consumers do not favour increasing their rates in order to fund improvements in system reliability. The survey results show that 58% of residential consumers and 84% of business consumers are unwilling to pay any more on their electricity bill in order to fund reliability improvements. However, 57% of the residential consumers and 62% of the business consumers surveyed indicated that they would not be willing to trade less reliability for a lower bill.

Despite the general satisfaction expressed by respondents, the survey results do indicate that consumers expect to see better reliability than they are currently receiving in terms of the number and duration of outages. Residential consumers anticipated that there would be 28% fewer outages and that outages would be 29% shorter than was reported to actually have been the case. Business consumers expected that there would be 46% fewer outages and that outages would be 62% shorter than was reported to have been the case.

D. STAKEHOLDER COMMENTS

In the initial stages of this consultation, distributors were asked to provide information on their current practices relating to the monitoring of system reliability performance and the use of performance information. A stakeholder conference was held subsequent to the posting of the PEG Report and the Pollara survey reports to provide a forum for discussion on issues related to the implementation of a system reliability standards regime in Ontario.

D.1 –Current Distributor Practices

Attached to the Board's August 23, 2010 letter was a list of questions designed to elicit information from distributors in relation to their current system reliability practices. 22 distributors responded to the information request.

The responses from distributors indicate that the tracking of outage information and system reliability performance is done either manually or through a combination of manual and automated methods. One quarter of the responding distributors indicated that they did not have or use a SCADA system. A number of the responding distributors that do have a SCADA system indicated that this system helps track only certain outages, such as those involving auto-reclosures or high voltage feeders. Most distributors rely on their Customer Information System or their Geographic Information System to determine the number of customers that have been affected by an outage.

All but one distributor reported having a formal process for using system reliability performance as a criterion for evaluating and prioritizing capital and maintenance projects. Of the responses received, the practice appears to be a yearly review of reliability trends and statistics to help determine where to direct expenditures.

One of the common ways to monitor and track reliability performance is to adjust a distributor's performance to remove the impact of "major events". Major events are those events that occur rarely but have a significant impact on the operation of a distribution system, like ice or wind storms. By normalizing the reliability data to remove the impact of major events, distributors are better able to determine year to year comparison of their reliability performance. There are different approaches for normalizing data for major events. These include the IEEE standard 1366, or individual distributor approaches. Only four of the 22 distributors are using the normalization methodology set out in the IEEE standard for taking extraordinary events into account when assessing reliability. Two other distributors reported developing their own approach for considering extraordinary events or using the Canadian Electrical Association's criteria for major events. Most distributors stated that they record that a major event occurred and track the costs related to that event, but do not use this information to adjust their reliability performance results.

In regards to other measures of reliability used by distributors beyond SAIDI, SAIFI and CAIDI, the tracking of momentary outages was the most common among the reporting distributors. In addition, a number of the reporting distributors track metrics related to the performance of individual feeders.

D.2 – Written Stakeholder Comments

Attached to the Board's October 7, 2010 letter was a list of issues for discussion at the stakeholder conference. Participants were invited to file written comments on those issues, as well as on the PEG Report, the Pollara survey reports and the distributor responses to the Board's information request. The following is a brief overview of the written comments filed by stakeholders.

There was a strong consensus amongst many participants that the Board should focus on ensuring that system reliability levels are maintained. These participants believe that the current regime is adequate for the purposes of ensuring continued sustainability and reliability. Representatives of distributors generally encouraged the Board to refrain from pursuing comprehensive and potentially expensive changes to the regulatory framework at this time. Some representatives of ratepayers expressed a similar concern to the effect that any additional regulatory standards imposed by the Board would simply result in increased electricity prices.

Several participants expressed concern about how reliability results will be affected by the introduction of smart meters. Certain stakeholders also identified as a concern the lack of consistent and accurate reliability data on which system reliability targets could be set. These stakeholders cited the need for improvements in distributor processes for defining, tracking, monitoring and calculating performance results, and suggested that the implementation of a mandatory reliability regime should wait until more consistent and accurate data is available through the use of smart meters. They noted that more robust data could, when available, be used to determine appropriate reliability measures and performance targets.

Ratepayer groups that supported the development of a new reliability regime were in the minority. Some ratepayer representatives suggested that reliability has declined almost continually over the last 8 years. A concern was also expressed that the Pollara survey results could be misinterpreted as meaning that all customers are satisfied with the level of reliability that they currently receive. At minimum, these groups recommended that the Board amend the service reliability guidelines immediately to preclude any interpretation that the guidelines set out in the two *Rate Handbooks*, (that a distributor with at least 3 years of data on a given index should, at minimum, remain within the range of its historical performance), allow for the deterioration of service reliability standards.

There was general agreement amongst stakeholders that that SAIDI and SAIFI would be adequate for measuring changes to overall reliability performance in the event that the Board were to proceed with the introduction of a mandatory reliability standards regime. Some participants commented that CAIDI is unnecessary, as it is a ratio of the other two indicators and can lead to misleading conclusions. It was noted by these participants that SAIFI and SAIDI can both be improving, but whenever SAIFI improves at a more rapid rate than SAIDI there will be an increase in CAIDI. While it was acknowledged that using MAIFI would add perspective on the impact of short duration outages, some participants expressed the concern that it would be costly and impractical to implement.[4]

[4] As noted earlier, distributors are now required to monitor and report on MAIFI, but only to the extent that their systems are capable of doing so.

Some ratepayer representatives supported the use of a “worst performing circuit” metric. However, representatives of distributors cautioned that automated distribution systems can be reconfigured on a regular basis such that the concept of a fixed feeder for which performance can be usefully monitored would not be relevant.

Several stakeholders noted that normalization of performance data (i.e., the exclusion of data related to major events like severe storms) would help standardize reported reliability measures across the province. Many participants suggested that using IEEE Standard 1366 would be appropriate for this purpose. However, other participants were not supportive of using this IEEE Standard, as they would prefer to use an approach similar to that used by Hydro One Networks Inc., which defines a major event as that which effects more then 10% of their customers.

Stakeholder comments indicated strong support for setting performance targets on an individual distributor basis. However, one participant argued that there is value in creating provincial-wide reliability targets to ensure that customers receive similar service in similar circumstances regardless of the service area in which they are located.

Most participants suggested that targets should be based on an average of five years of historic data.

A number of participants suggested that the Board make greater use of reported information on the cause of outages. Some stakeholders suggested that an outage should be measured not only so as to understand its duration but also to understand its origin (controllable, non-controllable, loss of supply, planned).

Both ratepayers and distributor groups suggested that in the future, there should be a move towards indicators and standards that are focused on the impact of outages on individual customers rather than system wide impacts.

There was some support for a restoration standard among representatives of ratepayers. Distributors that commented on this issue were generally opposed to the introduction of such a standard. They commented that the length of an outage can vary considerably based on local circumstances, and that response time is currently reflected in SAIDI (and, by definition, CAIDI) statistics.

A number of participants questioned whether the Board should introduce a penalty/reward system as part of the further development of the Board's system reliability regime. Some ratepayer representatives argued that distributors need to have an incentive to continually improve their systems. However, other ratepayer representatives and distributors expressed the concern that incenting distributors to focus only on a few measures, such as SAIFI and SAIDI, could incent behavior that is inconsistent with good utility practice.

A number of participants, both distributors and ratepayer representatives, suggested that reliability performance relative to established benchmarks should be addressed in rate applications rather than by means of the codification of standards. According to these participants, under a rate-setting approach distributors would be encouraged to look beyond simple statistics in assessing reliability performance and ratepayers would be provided with the opportunity to scrutinize a distributor's capital program with the goal of working towards a constructive approach to resolving any system reliability issues.

E. DISCUSSION AND RECOMMENDATIONS

E.1 – Overall Direction

A majority of stakeholders believe that the Board's current reliability regime is adequate for the purpose of maintaining appropriate system reliability levels, at least for the time being, and that the Board should therefore not move to codify reliability standards or performance targets at this time.

Based on the results of this consultation, it appears that there is no widespread sense that consumers are being provided with poor service, and it also appears that consumers prefer the status quo rather than risking an increase in rates for the purpose of funding reliability improvements.

However, Board staff believes that the Board should nonetheless pursue efforts to establish and codify system reliability measures and performance targets. Staff does not agree that system reliability performance should be the exclusive purview of rates proceedings. Staff notes, in this regard, that the manner in which a distributor manages its system reliability performance has been a topic of review in rates proceedings, especially in terms of the review of asset management plans and capital budgets, and staff expects this to continue to be the case. Staff also expects that the establishment of a formal reliability regime, with consistent and comparable performance data from year to year, will assist the Board in making judgments as to whether a distributor's capital expenditure for reliability purposes is reasonable and justifiable.

The codification of system reliability standards will ensure that distributors maintain an appropriate focus on service quality and on areas where capital investment and improved asset management are most needed. It would also address stakeholder concerns over what they in some cases perceive to be diminishing reliability. In addition, mandatory system reliability standards could alleviate the concern of some stakeholders that incentive regulation provides opportunities to maximize profit at the expense of customer service.

Board staff is mindful of the risk that implementation of a reliability standards regime will continue to be delayed in the face of new priorities that will always be evolving. However, Board staff agrees with stakeholders that the Board will be in a better position to establish reliability measures and performance targets once issues relating to the quality and consistency of system reliability data have been resolved. It appears that, at the present time, there are material inconsistencies in the manner in which distributors interpret the existing reliability indicators and in which they calculate performance results. In addition, there is also some question as to whether all distributors have adequate practices and protocols in place to ensure that reliability data is being collected and recorded properly.

Considerable work has already been done to improve the quality of much of the data that is being reported under the RRR. Staff believes that similar efforts should be undertaken, in consultation with stakeholders, with respect to system reliability data.

Staff also suggests that there are a number of issues that should be the specific focus of consultation with stakeholders in the near term for the purposes of improving the usefulness of reliability data and to assist the Board in its design of a robust and dynamic reliability standards regime. Those issues are discussed in the sections that follow.

E.2 – Normalization of Data

In order for a system reliability standards regime to be most effective, staff suggests that it is important to establish a consistent approach for normalizing data in light of major events. Staff's review of the reported reliability data indicates that a fair portion of distributors experience a significant change in performance from one year to the next For example, in one case a distributor's SAIDI performance went from 1.69 to 2.29 to 0.89 over three reported years. Staff believes that this type of fluctuation is likely largely the result of a major event experienced on the distributor's system.

Fluctuations of this type make it difficult to determine an appropriate performance target, even one based on 5 years of historical performance. As a result, staff recommends that if the Board establishes a mandatory regime of reliability measures and performance targets, such targets should be based on statistics which exclude major events through the methodology set out under IEEE Standard 1366. The IEEE Standard 1366 is recommended as it is an established methodology that is well recognized in jurisdictions around the world. It is also staff's view that the methodology used in the IEEE standard, (which determines a major event based on an outage which exceeds the average outage duration by certain percentage), to be a more reliable methodology then others that have been purposed.

It should be noted that use of IEEE Standard 1366 would not ultimately 'eliminate' the impact of any outage on reliability performance results, but rather would group outage events into two categories. The first would be performance results which exclude the impact of major events, which would be used to compute the reliability targets. The second category would be reliability performance statistics which include major event days. Distributors would be required to report their SAIFI and SAIDI values for each major event day, along with the cause(s) of major event day outages.

Staff also recommends that under a mandatory reliability regime distributors be required to measure and report their performance both inclusive and exclusive of the impact of major events. This information is still important for assessing a distributor's overall asset management program(s). However, for the ultimate purpose of assessing performance against a codified target, staff recommends that both the performance data and the performance target should be based on normalized data.

E.3 – Cause of Outages

Staff agrees that the cause of an outage is an important feature of the outage. Staff also believes that outages caused by factors within the control of a distributor are deserving of greater attention from the Board in the context of its regulation of that distributor. Staff therefore recommends that any mandatory reliability standards regime established by the Board include a component that allows the cause of the outage to have some impact on evaluating the performance of the distributor.

Staff acknowledges that distributors have recently been required by the Board to report SAIDI, SAIFI and CAIDI exclusive of loss of supply. Building upon this approach, staff suggests that the Board consider establishing performance targets that are based on outages that are within the control of the distributor rather than targets that are based on all outages.

E.4 – Customer Specific Measures and Performance Targets

Ontario's reliability regime currently measures *system* reliability, in other words reliability for the entire distribution system. Staff agrees that reliability measures that focus on the frequency and duration of outages experienced by individual customers may be more valuable than outage statistics based on the performance of the entire distribution system. Examples of such measures are "Customers Experiencing Multiple Interruptions" and "Customers Experiencing Long Duration Interruptions".

Staff believes that measures of this kind would be an important element of a robust reliability standards regime, provided that this can be accomplished without imposing a disproportionate burden on distributors. Based on the results of the surveys, reliability levels may have varying degrees of impact on customers depending on the type of customer, and in considering more customer focused types of reliability measures, staff suggest that consideration also be given to performance targets for different customer classes. Staff therefore recommends that these types of measures be explored further for eventual inclusion in a reliability standards regime.

E.5 – Worst Performing Circuits

Staff recommends that the Board adopt a Worst Performing Circuit measure. This measure is common in other jurisdictions, and can help to focus distributor resources on groups of customers who are receiving service at a level of reliability that is below the system average.

A number of distributors have reported that they currently track their feeder performance through various methodologies. As such, staff does not believe that the introduction of this new measure would place an undue burden on the industry. However, staff does believe that prior to implementation, consultation with the industry would be required to both ensure that a consistent approach is being used to monitor feeder performance and to determine a reasonable performance target.

F. NEXT STEPS

Board staff's principal recommendation above is that the Board proceed with the establishment and codification system reliability standards. In order to achieve that end, staff believes that the next step should be to engage stakeholders in further consultations aimed at:

1. resolving issues relating to the quality and consistency of reliability data gathered and reported by distributors; and

2. identifying any practical or other implementation issues associated with the introduction of the new elements recommended by staff as described in sections E.2 to E.5 above, as well as the means by which those issues can best be resolved.

Report of the Board on
3rd Generation Incentive Regulation of Ontario's Electricity Distributors
July 14, 2008

Ontario Energy Board

Report of the Board

on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors

July 14, 2008

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1 Introduction

Purpose

In 2006, the Board announced its intention to implement a multi-year rate-setting plan for distributors (the "Rate Plan"), to be effected through a number of initiatives. The Board has since confirmed the cost of capital to be used in adjusting annual revenue requirements for 2007 and beyond, and established a mechanistic price cap rate adjustment ("2nd Generation IR") for electricity distributors over the period 2007 to 2009. The Board has issued a report which sets out its policy on key rate-making issues that may be associated with consolidation in the electricity distribution sector and which builds on and complements the work of the Board in relation to incentive regulation. Work has also concluded on the regulatory framework for conservation and demand management ("CDM") activities undertaken by electricity distributors, and on the codification of the service quality requirements for electricity distributors. The Board continues its electricity distributor cost allocation review, and has consulted with the sector on a comparative utility cost analysis methodology for electricity distributors. Also, the Board is examining the design of electricity distribution rates in light of emerging issues and industry developments in relation to matters such as metering, CDM, and distributed generation.

Board staff have undertaken research, commissioned expert advice and consulted with stakeholders on the principles and methodology for the 3rd generation incentive regulation ("3rd Generation IR") mechanism that will be used to adjust electricity distribution rates starting in 2009 for those distributors whose 2008 rates were rebased through a cost of service review.

Consultations were informed by the advice of: Dr. Lawrence Kaufmann of the Pacific Economics Group, LLC ("PEG"), staff's consultant; Prof. Adonis Yatchew of the University of Toronto, consultant to the Electricity Distributors Association; Dr. Francis

Cronin, consultant to the Power Workers' Union; and Ms. Julia Frayer of London Economics International, LLC, consultant to the Coalition of Large Distributors (Enersource Hydro Mississauga Inc., Horizon Utilities Corporation, Hydro Ottawa Limited, PowerStream Inc., Toronto Hydro-Electric System Limited and Veridian Connections Inc.) and Hydro One Networks, Inc.

These consultations considered all of the necessary elements of an IR mechanism framework including the form and term of the plan, the inflation and productivity factors, the potential for earnings sharing, and the treatment of unforeseen events. The consultations also included a focus on specific issues associated with capital investment to support infrastructure maintenance and development, lost revenue due to changes in electricity consumption and distributor diversity. These activities began in August 2007 and have culminated in the policies set out in this report.

This report sets out the Board's policies and approach to 3rd Generation IR and presents guidelines that the Board expects distributors to use in preparing their rate applications. With few exceptions, this report represents the Board's final determination of its policies regarding 3rd Generation IR. As indicated elsewhere in this report, the Board will consult further on the outstanding issue of the values for the productivity factor, the stretch factor, and the capital module materiality threshold before determining those values. The Board will also in due course provide further guidance on the issue of tax changes in relation to the Z-factor (see section 2.6).

Organization of this Report

This report is organized as follows. The Board's policy for, and analysis of, 3rd Generation IR are outlined in Section 2 with brief descriptions of the matters being addressed, the Board's policies and rationale, and summaries of the issues and options raised in consultations. Written comments made by participants throughout this consultation have been considered by the Board in developing the policies set out in this report, and are available from the Board's website. This report makes reference to participant comments to the extent necessary, but does not contain an exhaustive description of those comments.

Section 3 outlines in more detail how and when the adjustments to distribution rates will be implemented. Section 4 provides a summary. Section 5 contains a guide to assist interested participants in preparing their presentations at a stakeholder conference that will be held the week of August 5, 2008 to address the outstanding values referred to above. Guidelines associated with the policies set out in this report are provided as an Appendix.

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2 Elements of the Plan

This is the third time the Board has adopted an incentive rate setting mechanism for electricity distributors. The first mechanism was established in 2000 ("1st Generation IR") and is described in the Board's first electricity distribution rate handbook. The second mechanism - 2nd Generation IR - was established in 2006 and is set out in the December 20, 2006 "Report of the Board on Cost of Capital and 2nd Generation IR for Ontario's Electricity Distributors".

Building incrementally on the 2nd Generation IR plan, the 3rd Generation IR plan is a more sustainable incentive regulation ("IR") plan for electricity distributors. The 3rd Generation IR plan is more specifically grounded in empirical analysis and takes the differences in the operations of distributors into account.

2.1 Form

There are various approaches to IR. Two popular approaches that use indexing are price caps and revenue caps – a price cap sets the maximum price that a distributor may charge, and a revenue cap sets the maximum allowable revenue requirement.

Issues and Options Raised in Consultation

The February 28, 2008 Board staff Discussion Paper on 3rd Generation IR for Ontario's Electricity Distributors (the "Discussion Paper") described various forms of IR and various individual mechanisms to address the specific issues associated with capital investment, lost revenue and distributor diversity.

Prof. Yatchew provided an analysis of three alternative approaches that were described in the Discussion Paper and that combine some of those mechanisms. In his presentation to participants during the stakeholder meeting held on May 6, 2008, Prof.

Yatchew commented that under comprehensive multi-year cost of service, incentives are substantially less powerful relative to properly implemented IR; and moreover, the regulatory burden is high for the regulator and distributors. He noted that the hybrid approach (under which OM&A would be indexed and capital costs would be forecasted) would create incentives to increase capital expenditures, in order to maintain or improve a good OM&A performance profile - a disadvantage of the hybrid approach. According to Prof. Yatchew, the third approach, the comprehensive price cap index, has the highest efficiency incentives, if properly implemented. However, he also observed that while the comprehensive price cap is by far the most appealing, it has the potential of doing financial harm for some distributors in contrast with the revenue cap, particularly those that are experiencing declining per-customer energy consumption.

Policy and Rationale

The Board will retain a comprehensive price cap form of adjustment mechanism for electricity distributors. The price cap, used in the 1st and 2nd generation IR plans, continues to be supported by distributors and other stakeholders and is a simple approach that will, along with the implementation of mandatory service quality requirements, provide balanced incentives for efficiency improvements and the maintenance of adequate service quality over the course of an IR term. The concern of potential financial harm for some distributors in contrast with revenue caps is mitigated by the other elements of the 3rd Generation IR plan described in this report.

2.2 Term

Staff's consultations over the last year have considered IR plan term length in dealing with the specific issues associated with capital investment to support infrastructure maintenance and development, lost revenue due to changes in electricity consumption and distributor diversity. The longer the period of time between rate rebasings (i.e., the longer the IR plan term), the greater the potential need for some form of special treatment of incremental capital investment and/or lost revenues. Also, one way to recognize distributor diversity in an IR plan may be to give the distributor choice with respect to the length of the plan term. By and large, capital replacement, distributor diversity and similar issues are likely to be more manageable with shorter plan terms.

Issues and Options Raised in Consultation

In the Discussion Paper, seeing merit in allowing for flexibility in the plan term, staff suggested that distributors have the choice of plan term which could vary from three to five years. In a presentation during the stakeholder meeting held on May 6, 2008, staff proposed a fixed term of four years (i.e., rebasing year plus four years) as a reasonable plan term. This proposal was in response to the varied comments received on the need for a shorter or longer term and to concern over giving distributors choice. Further consultation on this issue continued to demonstrate a divergence of opinion.

Policy and Rationale

The Board has determined that the plan term for 3rd Generation IR will be fixed at three years (i.e., rebasing year plus three years). The rates of the distributor are not expected to be subject to rebasing before the end of the plan term other than through an eligible off-ramp.

The Board is of the view that a shorter term is appropriate in view of important refinements anticipated by 2012 to empirical work on the electricity distribution sector, including total cost benchmarking, an Ontario total factor productivity ("TFP") study, and input price trend research. Participant support for a shorter term is evident in their concerns over distributor data limitations, evolving government policy which continues to mandate new roles for Ontario distributors, and the Board's commitment to reviewing rate design policies.

2.3 Inflation Factor

Under cap mechanisms, changes in price indices drive allowed changes in output prices for regulated services (i.e., indices escalate the allowed prices).

The inflation factor could be established in two ways: either an industry-specific price index ("IPI") designed to track the inflation of the industry inputs, or a macroeconomic index.

Issues and Options Raised in Consultation

The choice of inflation factor affects the X-factor. When an IPI is used, the X-factor has two main components. The first is the productivity factor, and the second is the stretch factor. When economy-wide inflation factors are used, the X-factor has additional components to capture the expected difference between changes in the selected inflation factor and input prices for the regulated industry. This difference is often referred to as the input price differential. Depending on how the productivity factor in an index is derived, a productivity differential may also be considered in conjunction with an economy-wide inflation factor in order to reflect any differences. As explained by Dr. Kaufmann in his presentation to participants at the stakeholder meeting held on May 6, 2008, input price differentials can be measured directly by comparing the change in industry input prices to the change in the selected economy-wide inflation measure. This approach is mathematically equivalent to computing both "productivity differentials" and "input price differentials," but it is simpler and requires less information. Computing an input price differential in this manner therefore eliminates the need to obtain estimates of economy-wide TFP trends which are needed to compute both productivity and input price differentials.

In the Discussion Paper, staff provided an illustrative example of an IPI using the methodology adopted by the Board in the 1st Generation IR with a different labour price index and different weights calculated by PEG to reflect the most recent cost structure.

The Discussion Paper invited comments on this illustration, the choice of the indices and the options to address the volatility of the resulting IPI. In light of participants' comments, summarized below, at the May 6, 2008 stakeholder meeting staff proposed the use of a macroeconomic index (the Canada Gross Domestic Product Implicit Price Index for final domestic demand or "GDP IPI FDD") instead of an IPI, and asked PEG to estimate the requisite input price differential. To do this, PEG looked at the relationship between input prices of the industry and the selected macroeconomic inflation measure. PEG examined the relationship between input price trends for Ontario distributors and Canada's GDP IPI FDD, as well as the relationship between input prices for U.S. distributors and a measure of US economy-wide inflation (the GDP-PI). PEG found that economy-wide inflation was much greater than industry input price inflation in Ontario, while in the U.S. the opposite was true. PEG was of the view that this disparity demonstrates that there is considerable uncertainty about the appropriate value for an input price differential in 3rd Generation IR. In the absence of persuasive empirical evidence, PEG therefore recommended an input price differential equal to zero.

Generally, participants agreed with the benefits of an IPI. However, concerns were expressed about implementation details of the IPI. Some of these concerns referred to the choice of input price indices and whether distributor-specific data would better track the inflation of inputs. Also, some participants commented on the weights of the sub indices. Many participants expressed concern about the methodology used for the calculation of the capital price sub index and the resulting volatility. Some participants proposed alternative approaches to smooth the index, while distributors suggested that further work is required to ensure that the index tracks actual cost pressures and reflects distributor costs going forward and suggested that in the meantime, the Board use a macroeconomic index.

Support for the use of the GDP IPI FDD and PEG's recommended input price differential was mixed. While some participants accepted the proposal, other participants continued to support the use of an IPI or expressed concern over the issue of tax changes in relation to the GDP IPI FDD (as it is currently being considered in the

EB-2007-0606/615 proceeding in relation to gas distributor incentive regulation) or disagreed with the recommended input price differential. In particular, three participants estimated non-zero input price differentials. One participant representing a group of ratepayers estimated that the input price differential should be positive 0.43% based on the Ontario differential calculated by PEG. Another participant proposed that the differential should be positive 0.65% and argued that a differential of zero would be unfair to ratepayers and that the number should be based on judgment rather than on empirical studies. Dr. Cronin argued that the input price differential should be different from zero because distributor input prices have consistently grown more slowly than macro input prices. Based on a historical assessment of trend relationships, Dr. Cronin proposed a negative differential, estimating that based on Ontario data the input price differential has ranged from -1.1 to -2.3 over the last twenty years. Dr. Cronin also calculated productivity differentials and showed that for various periods this differential has also been non-zero.

Policy and Rationale

The Board will use the Canada Gross Domestic Product Implicit Price Index for final domestic demand (GDP IPI FDD) as the inflation factor.

The Board is of the view that a macroeconomic index is easier to implement for 3rd Generation IR: only one index needs to be obtained and the only calculation necessary will be the annual change in the index. In addition, the macroeconomic index that will be used, GDP IPI-FDD, tends to grow at a relatively stable rate over time and it is familiar to Board staff and stakeholders, since it is currently being used in 2nd Generation IR and in both gas IR plans.

The Board recognizes that an IPI would track industry input price fluctuations better than an economy-wide measure. It may better mitigate significant gains and losses that might result from the failure of a macroeconomic index to track industry input price inflation. However, the Board observes that the implementation of the IPI methodology that was used in 1st Generation IR with recent data produces a very volatile index, as shown in the illustrative example presented in the Discussion Paper. Such volatility could be harmful to both ratepayers and distributor shareholders, if reflected in rates. The Board believes that further research is required on the methodological approach to address such volatility and to ensure that the chosen sub indices appropriately track the inflation faced by the industry.

The Board has determined that the input price differential in 3rd Generation IR will be equal to zero.

A sustainable incentive regulation framework requires confidence in the parameters of the rate adjustment formula, and without greater certainty on input price trends in the sector, the Board believes that the determination of an input price differential is premature. Absent a solid methodology for the calculation of the industry IPI for Ontario as well as a TFP based on Ontario data, the Board is concerned that an input price differential that is not equal to zero may result in rates that are not just and reasonable from the perspective of both ratepayers and distributors. Therefore, until Ontario data are used to set the productivity factor in the indexing formula, the Board believes that a value of zero for the input price differential is reasonable for 3rd Generation IR.

Participant comments reinforce to the Board that further research is needed to better understand the input price trends of Ontario electricity distributors before an IPI or an input price differential can be considered for implementation. This research could be carried out for consideration in future IR plans.

Implementation

The Board will continue to use the year-over-year change in the GDP IPI FDD (Series V3840594) to calculate price escalation. The change will be calculated early in March, once Statistics Canada publishes the last year’s index and the latest available information on any changes to the index of two years ago. As with 2nd Generation IR, there will be no explicit adjustments for return on equity or debt costs.

2.4 Productivity and Stretch Factors

Under a price cap mechanism, the allowed rate of change in the price of regulated services is restricted by the growth in an inflation factor minus an X-factor. Generally, the X-factor has two main components: the productivity factor and the stretch factor.

The productivity component of the X-factor is intended to be the external benchmark which all firms are expected to achieve. It should be derived from objective, data-based analysis that is transparent and replicable. Productivity factors are typically measured using estimates of the long-run trend in TFP growth for the regulated industry.

The stretch factor component of the X-factor is intended to reflect the incremental productivity gains that firms are expected to achieve under IR and is a common feature of IR plans. These expected productivity gains can vary by company and depend on the efficiency of a given company at the outset of the IR plan. Stretch factors are generally lower for firms that are relatively more efficient.

Issues and Options Raised in Consultations

PEG's report entitled "Calibrating Rate Indexing Mechanisms for Third Generation Incentive Regulation in Ontario" (the "PEG IR Report") makes specific recommendations for the productivity and stretch factor components of the X-factor and provides a discussion of relevant IR precedents.

In brief, PEG recommended in the PEG IR Report that for Ontario distributors, the X-factor be comprised of: (1) an industry TFP-based component reflecting TFP growth potential estimated using U.S. data; and (2) an efficiency benchmark-based stretch factor based on Ontario data.

The Productivity Factor

As detailed in the PEG IR Report, TFP trends were computed using an index based approach and on three sets of available data: U.S. data for the period 1988-2006, Ontario data for the period 1988-1997, and Ontario data for the period 2002-2006. Ontario data for the period 1998-2001 was not available. Dr. Kaufmann noted the results of these analyses show a slowdown in productivity in the most recent years of the U.S. TFP trend and in the latest Ontario TFP trend, and expressed uncertainty over the persistence of the trend. In the case of Ontario, Dr. Kaufmann advised in the PEG IR Report that four years of TFP changes are insufficient to compute a reliable, long-run TFP trend. He also believed that there is an identifiable, downward bias in the Ontario TFP measure which could not be explained given available information, and that the quality of the Ontario TFP measure was generally diminished by the lack of available data (especially data on distributors' capital additions). In the case of the U.S., Dr. Kaufmann commented that much of the measured TFP decline for the U.S. electricity industry in the period 2002-2006 was due to transitory factors that will not persist.

Because of concerns with relying solely on the four years of Ontario data, the recommendation in the PEG IR Report for the productivity factor was based on a comparative analysis of TFP growth between 1988 and 2006 for the U.S. and Ontario electricity distribution industries. TFP growth for Ontario distributors in the period 1988-1997 was previously computed for the purposes of the 1st Generation IR, and PEG considered this information as well as the trends it computed for Ontario distributors in 2002-2006 and for the U.S. industry for the entire 1988-2006 period. Dr. Kaufmann concluded that TFP trends for U.S. power distributors were a reasonable, although not perfect, proxy for contemporaneous TFP trends in Ontario. Overall, the average TFP growth rate for the Ontario TFP industry was almost identical to the average TFP growth rate for the U.S. industry over the thirteen years for which TFP growth could be computed.

PEG's analysis concluded that: 1) there was not enough historical data to compute a long-run TFP estimate for the Ontario distributors; and 2) TFP growth of U.S. distributors was a reasonable proxy for the Ontario industry. Therefore, PEG's recommended productivity factor was based on the long-term TFP trend for the U.S. electricity distribution industry. In the TFP study, PEG determined its sample period using a "start date analysis" designed to ensure that the estimated TFP trends were not affected by transitory conditions, such as abnormal economic or weather conditions, which can distort measured TFP trends. Based on this analysis, PEG chose a sample period of 1995 to 2006. PEG's recommended productivity factor of 0.88% was equal to the average rate of TFP growth for U.S. electricity distributors over this period.

The consultants retained by participants agreed that the index based approach is appropriate. However, their views differed as to the details involved in carrying out the analysis.

Four participants commented on the issue of the sample period used in PEG's TFP study. Two participants supported PEG's analysis to select the sample period and two participants did not. Prof. Yatchew disagreed with PEG's selected sample period. He argued that PEG's approach is conceptually deficient because, in selecting the start of the period, PEG's analysis searched for only a single year that is likely to be most similar to the most recent year in terms of factors that could distort TFP, rather than searching for an entire period that is likely to be representative of the future.

Dr. Cronin did not support PEG's recommended approach for developing a productivity factor for three main reasons: the belief that the U.S. industry was too dissimilar to that in Ontario to provide a basis for a productivity factor; the belief that PEG's measure of capital was flawed; and concern that PEG's output measure was incorrectly specified. Rather than having a single productivity factor, Dr. Cronin recommended a productivity factor-menu approach. Distributors would be allowed to select from a menu of productivity factors, each with an associated allowed return on equity ("ROE"). The "baseline" option would be a productivity factor of 0.8% with an associated allowed ROE of 8.5%. The proposed menu also included four other options, where increments of 0.2% in the productivity factor are associated with 100 basis point increments in the allowed ROE. The maximum productivity factor of 1.6% was therefore associated with a 12.5% allowed ROE.

In general, distributors raised similar concerns in their comments. These participants noted that the average TFP growth for the U.S. electricity distribution industry was 0.72% over the 1988-2006 period. These participants also noted that TFP has decelerated in both the U.S. and Ontario in recent years. They further argued that there are likely to be continued cost pressures over the term of 3rd Generation IR due to, among other things, increasing capital replacement expenditures and the impacts of government policy. These participants therefore expressed the belief that more emphasis should be placed on the Ontario TFP data, and greater weight put on the recent trend evident from that data, as the basis for the productivity factor. Ms. Frayer raised concerns that PEG's computed TFP trend did not include peak demand as an output measure. She also commented that PEG's capital measures for Ontario are likely to be biased. Ms. Frayer developed an alternative TFP measure that included peak demand and substituted a physical measure of capital (total distribution line length) for the inflation-adjusted, monetary value of capital. According to this specification, TFP for Ontario distributors declined between 1.3% and 2.5% per annum over the 2002-2006 period. In summary, distributors recommended a productivity factor of 0.55% for 3rd Generation IR. This recommendation was based on the midpoint of what these participants believed was a reasonable range of TFP growth rates estimated by Prof. Yatchew and Ms. Frayer. These participants argued that it was reasonable to have a lower TFP target than that recommended by PEG given the recent deceleration in TFP. They also argued that this approach was consistent with a Board precedent, since the productivity factor approved for purposes of the 1st Generation IR placed more weight on recent TFP growth than on more distant TFP growth.

Participants representing ratepayers generally supported PEG's recommended approach for establishing a productivity factor. Two groups commented that using the

U.S. data as a basis for the productivity factor was reasonable until sufficient Ontario data could be developed. Two other participants representing ratepayers commented that PEG's research shows that TFP trends for the U.S. industry are a reasonable proxy for contemporaneous Ontario trends. All of these participants supported PEG's recommended productivity factor of 0.88%.

The Stretch Factor

As described in the PEG IR Report, PEG's recommended stretch factors are informed by work it has done for Board staff in a separate project on the benchmarking of Ontario distributors' OM&A costs[1]. The PEG IR Report did not present final, recommended stretch factor assignments and values because the benchmarking work had not been finalized at the time the report was issued. The PEG IR Report illustrates a methodology for using these benchmarking evaluations to assign stretch factors to distributors. Distributors were assigned by PEG to different efficiency cohorts based on the following benchmarking evaluations:

Table 1: PEG's February Proposal

Group	Benchmarking Evaluations
I	Statistically superior
II	Not statistically superior but in top third on OM&A unit cost comparison
III	In middle third on OM&A unit cost comparison
IV	Not statistically inferior but in bottom third on OM&A unit cost comparison
V	Statistically inferior

Given these identified efficiency cohorts, PEG recommended stretch factors that were the same for all firms in a given cohort but differed between cohorts. Smaller stretch factors were assigned to the more efficient cohorts. More particularly, Group I had a

[1] The March 20, 2008 final report prepared for Board staff by PEG, entitled "Benchmarking the Costs of Ontario Power Distributors" (the "PEG Benchmarking Report") details the benchmarking evaluations and is available on the Board's web site.

recommended stretch factor of 0, Group II had a recommended stretch factor of 0.15%, Group III had a recommended stretch factor of 0.3%, Group IV had a recommended stretch factor of 0.45%, and Group V had a recommended stretch factor of 0.6%. These specific values were based on judgment but were also broadly supported by precedents from North American index-based IR plans. However, in light of participant comments, as summarized below, Dr. Kaufmann presented a revised proposal at the May 6, 2008 stakeholder meeting. In response to staff's request to simplify the proposal, the number of efficiency cohorts and stretch factors was reduced from five to three, and distributors were assigned to different efficiency cohorts based on the following benchmarking evaluations:

Table 2: PEG's Revised Proposal

Group	Benchmarking Evaluations
I	Statistically superior and in top quartile on OM&A unit cost comparison
II	In middle two quartiles on OM&A unit cost comparison
III	Statistically inferior and in bottom quartile on OM&A unit cost comparison

This updated recommendation led to a kind of "bell curve" for efficiency evaluations. That is, about two-thirds of Ontario distributors were in the middle and "average" performers in Group II, about one-sixth of the distributors were identified as "superior" performers in Group I, and about one-sixth of the distributors were classified in Group III.

In this revised proposal, PEG also linked its recommended values for the stretch factors more closely to regulatory precedents from Ontario rather than from all of North America. In the revised proposal, the stretch factor for Group I was 0, the stretch factor for Group II was 0.25%, and the stretch factor for Group III was 0.5%. These values generally conform to the values approved to date in Ontario, where 0.47% and 0.5% were the stretch factors approved in the early Enbridge and Union plans, respectively, and 0.25% was the stretch factor approved for all distributors in the 1st Generation IR plan.

Most participants supported the concept of stretch factors. However, participants differed on the appropriate magnitudes of stretch factors and whether the available data and analysis were sufficient to support the use of differentiated stretch factors at the present time.

Most participants representing groups of ratepayers generally supported PEG's approach to both proposals but believed the proposed values for the stretch factors were too low.

Several participants did not support PEG's recommended approach to both proposals because the underlying benchmarking evaluations focus on OM&A costs only. Some of these participants argued that benchmarking must also consider capital costs and reliability in order to benchmark company performance appropriately. They also commented that a benchmarking study that focuses only on OM&A can create perverse incentives to cut operating costs, which can be achieved through excessive capitalization or at the expense of reliability. As an alternative, one participant proposed a menu approach, in which distributors could select one of five stretch factors that ranged between 0.15% and 0.75%. Under this proposal, all distributors would be subject to an earnings sharing mechanism, and those firms selecting the higher stretch factors would be allowed to retain greater shares of their actual earnings. Dr. Cronin also supported a menu approach.

Prof. Yatchew commented that there was no theoretical rationale supporting the need for a stretch factor at the present time. He argued that stretch factors were warranted only immediately after distributors switched from cost of service regulation to IR. Because he maintained that Ontario distributors have been subject to some form of IR since 2000, he did not support a stretch factor and commented that it would be unreasonable to expect acceleration in productivity growth on this basis. As an alternative to stretch factors, Prof. Yatchew suggested that "diversity factors," that could be positive or negative relative to the industry TFP, may be more appropriate.

However, he and some other participants representing distributors also maintained that there is no evidence of productivity differences among the distributors. In spite of these fundamental concerns, some distributors did support the application of stretch factors in principle but claimed that they should be deferred until appropriate data and benchmarking analyses that focus on the total cost of distribution services could be developed.

In response to PEG's revised proposal, most participants reiterated their prior comments. One participant representing ratepayers did not support PEG's approach of establishing separate stretch factors for different distributors and recommended that a single stretch factor of 0.5% be applied to all firms.

Policy and Rationale

The Board has determined that X-factors for individual distributors will consist of an empirically derived industry productivity trend (productivity factor) and stretch factor. The approach to setting these factors will be based on economic theory and empirically derived from objective, data-based analysis.

The Productivity Factor

The index based approach is widely used in other jurisdictions for the purpose of calculating TFP. In addition, the approach is simpler compared to the alternative "econometric" approach and is therefore better understood by stakeholders.

Implementation

All distributors will be subject to the same productivity factor that will be set at the start of 3rd Generation IR and will remain fixed throughout the term of the plan. This will provide distributors with greater certainty as to the time to achieve or surpass the external benchmark and retain any achieved savings. The Board's Rate

Plan for the electricity distribution sector will stagger distributors' commencement onto 3rd Generation IR. To set the external benchmark that all distributors will be expected to achieve, the productivity factor will be the same for all distributors regardless of when they commence the plan.

While it is clear to the Board that participants support an index based approach for the derivation of an industry productivity trend to form the basis for the productivity factor for the IR plan, the Board would be assisted by further consultation on the interpretation of the results in order to determine the appropriate value for the productivity factor. The issue of the appropriate value for the TFP trend for 3rd Generation IR will therefore be included on the agenda for the August stakeholder conference (see Section 5).

The Stretch Factor

The Board has determined that non-negative (i.e., >0 or =0) stretch factors will be included in the X-factor. The Board believes that stretch factors are required in 3rd Generation IR and is not persuaded by the arguments that stretch factors are only warranted immediately after distributors switch from years of cost of service regulation to IR. Productivity stretch factors promote, recognize and reward distributors for efficiency improvements relative to the expected sector productivity trend. Consequently, stretch factors continue to have an important role in IR plans after distributors move from cost of service regulation.

On the issue of the application of benchmarking to OM&A costs rather than total cost, The PEG IR Report describes OM&A benchmarking as a well-established technique with ample precedent in the academic literature and regulatory proceedings. Further, OM&A benchmarking can lead to appropriate inferences on a firm's efficiency provided that the model contains appropriate controls for capital stock. PEG's econometric model included two such capital-related control variables. The Board notes that the consultants generally agree that benchmarking OM&A costs is, in principle, a legitimate benchmarking approach, although they disagree as to whether PEG's analysis has sufficient controls for capital. In contrast to 2nd Generation IR, where all distributors were subject to the same X-factor, the Board is of the view that, as an incremental approach for 3rd Generation IR, distributor diversity should be recognized. The Board does not agree with comments that there is no evidence of productivity differences within the sector. The Board's comparative cost analyses demonstrate that there is a range of productivity levels across distributors. These differences in measured productivity levels support the position that distributors have different abilities to achieve incremental productivity gains and, therefore, that it may be appropriate to have different stretch factors for distributors.

Therefore, **the Board has concluded that distributors will be assigned to one of three groups with stretch factors based on their efficiency as determined through comparative cost analysis**. Using the resultant efficiency ranking, superior performers could be assigned a lower stretch factor and inferior performers could be assigned a relatively higher stretch factor. All others could be assigned an average stretch factor.

Establishing the Efficiency Ranking

The Board will use the results of two benchmarking evaluations to divide the Ontario industry into three efficiency "cohorts." Until total cost data is available, and the models are revised in consultation with stakeholders to carry out total cost benchmarking, these evaluations will be done using the most recent three years of OM&A cost data available in July of each year. For example, for the 2009 rate year the efficiency evaluations will be based on efficiency evaluations done using OM&A cost data for the years 2005, 2006 and 2007.

The first benchmarking evaluation will use an econometric model to assess the efficiency of each distributor's costs. The econometric model set out in the PEG Benchmarking Report controls for the impact of various factors beyond management control on a distributor's OM&A costs. These factors, determined by PEG's analysis to be significant drivers of OM&A costs, include the number of customers served, kWh deliveries, the price of OM&A inputs (including labour), the percent of distribution line that was underground, system age and whether or not the distributors' territory is located on the Canadian Shield. This benchmarking model will be used to predict each distributor's OM&A costs, and the distributor's actual OM&A costs will be compared to the econometric prediction. A distributor will be deemed to be "statistically superior" if its actual OM&A costs are lower than the costs predicted by the econometric model and the difference is statistically significant. A distributor will be deemed to be "statistically inferior" if its actual OM&A costs are higher than the costs predicted by the econometric model and the difference is statistically significant. All distributors that are neither statistically superior nor statistically inferior will be deemed to be average cost performers.

The second evaluation will be based on comparisons of distributors' OM&A costs per unit of comprehensive distribution output. These unit cost evaluations will be based on a comparison between a given distributor's unit OM&A costs and the average unit OM&A costs of a peer group. There are a total of 12 peer groups identified in the PEG Benchmarking Report, which are defined based on the size of distributors, location in the Province (Northern, Southern or Greater Toronto Area), the degree of undergrounding, and whether the distributor has been experiencing rapid growth. PEG determined that these factors were most strongly associated with similarities in unit cost levels across distributors.

The two evaluations will then be compared and those distributors that rank superior in both will be assigned to Group I. Those distributors that rank inferior in both will be assigned to Group III. All other distributors, including those that rank superior or inferior in only one of the evaluations, will be included in the broad middle cohort, Group II, as shown in Table 3.

Table 3: Efficiency Cohorts for Stretch Factor Assignments

Group	Benchmarking Evaluations
I	Statistically superior and in top quartile on OM&A unit cost comparison
II	In middle two quartiles on OM&A unit cost comparison
III	Statistically inferior and in bottom quartile on OM&A unit cost comparison

Using this approach, the Board expects that the resultant efficiency ranking will approximate a normal distribution (i.e., “bell curve”) where about two-thirds of Ontario distributors will be in the middle and “average” performers, about one-sixth of the distributors will be identified as “superior” performers in Group I, and about one-sixth of the distributors will be classified in Group III.

Implementation

Each year the cohorts for the entire sector will be re-evaluated. This means that the stretch factor for a given distributor may change during the term of the IR plan. This approach will recognize and reward distributors for efficiency improvements during the term of the IR plan. A distributor’s individual ranking can be directly affected by its own efforts and can also be affected by the efficiencies achieved by other distributors. This means, for example, that a distributor initially ranked as a superior performer must continue to outperform its peers to maintain that ranking and associated stretch factor. The approach will call for the Board to publish revised cohort rankings by the end of August each year. This will give distributors sufficient time to incorporate changes in their individual stretch factors when they apply to have their rates set for the following year.

However, while the Board has determined that there will be three stretch factors representing diversity of efficiency and that these will be revised annually to reflect changes in efficiencies in the sector, the Board has not yet determined what the three stretch factor values will be. The Board would be assisted by

further consultation on the appropriate stretch factor values for the three groups for 3rd Generation IR. The issue of the appropriate stretch factor values will therefore be included on the agenda for the August stakeholder conference (see Section 5).

2.5 Incremental Capital

In the consultation on 2nd Generation IR that occurred in 2006, a number of participants commented that the IR regime needs to ensure that sufficient incentives are available in order to achieve efficiencies, recognizing the time patterns of costs and savings; and to provide for the expeditious review and approval of capital expenditure programs. Some participants argued that certainty in relation to capital expenditures beyond the single future test year is needed. It was suggested that the regime could include some form of approval of a multi-year capital plan and not just capital items that may arise in the following year.

In its July 23, 2007 "Report of the Board on Rate-making Associated with Distributor Consolidation" and associated covering letter, the Board indicated that electricity distributors' concerns over partial rebasing to account for needed capital expenditures should be examined as part of the development of the 3rd Generation IR plan.

Issues and Options Raised in Consultation

Staff's Initial Proposals

The Discussion Paper noted that participants differed as to whether special treatment of capital spending is necessary in an IR framework; however, the Discussion Paper described an option that staff thought might be reasonable. The approach would allow for the intra-term approval by the Board and appropriate pass-through of incremental capital expenditures associated with growing capital program demands. Dr. Kaufmann advised in his May 6th presentation to participants that implicit in an X-factor is a historical pattern of capital expenditures for the industry, and that generally a separate capital module should not be required under a comprehensive rate indexing plan. However, he commented that if, going forward, projected capital investment is substantially different than the history of what is reflected in the X-factor, then there could be an issue and a capital module could be designed to address the disparity.

At the May 6, 2008 stakeholder meeting, staff proposed the introduction of an incremental capital module as a flexible and practical means of accommodating reasonable spikes in incremental capital investment needs during 3rd Generation IR. In brief, staff proposed that the module should only be invoked by a distributor intra-term and that any Board-approved amounts and rate base treatment should be fully resolved through comprehensive rebasing.

Under staff's proposal, in order to invoke the module a distributor would make specific application to the Board for review and approval. Staff proposed that the application would substantiate the need for incremental capital due to drivers that are non-discretionary in the control of the distributor's management such as: life-cycle replacement of aging distribution plant; and additions of non-revenue earning plant to meet new growth demands and/or address system impacts from customer choice of location for connection. Further, for incremental capital expenditures to be considered for recovery, staff proposed that the amounts would have to satisfy the eligibility criteria listed in Table 4.

Table 4: Staff's Proposed Incremental Capital Investment Eligibility Criteria

Criteria	Description
Causation	Amounts should be directly related to the claimed driver, which must be clearly non-discretionary. The amounts must be clearly outside of the base upon which rates were derived.
Materiality	The amounts must have a significant influence on the operation of the distributor; otherwise they should be dealt with at rebasing.
Prudence	The amounts to be incurred must be prudent. This means that the distributor's decision to incur the amounts must represent the most cost-effective option (not necessarily least initial cost) for ratepayers.

Staff further proposed that applications should be accompanied by comprehensive evidence to support a claim for incremental capital and that subsequently there should be annual reporting requirements on actual amounts spent.

With regard to a materiality threshold, staff proposed a threshold of 25% of the capital budget reflected in base rates going in to IR and that the threshold must be met on an individual driver basis.

Staff's Revised Proposal

In response to participant comments, as summarized below, staff revised its proposal as described in the Board's May 15, 2008 letter to participants. To address comments from distributors, staff proposed a threshold of the distributor's average annual CAPEX since the Board-approved base year relative to 150% of the distributor's depreciation expense embedded in base rates. Staff believed that 150% would be appropriate in order to allow for the impact of inflation and to provide a cushion to ensure that only serious cases of incremental capital need are considered.

Staff also proposed changes in relation to the proposed scope for capital expenditures eligible for recovery through the module. Staff noted that, to date, revenue-earning plant had not been included in discussions. However, for reasons of simplicity, staff suggested that the threshold test be indifferent to the driver, and proposed instead that the need driving any amount applied for by a distributor should be dealt with in the distributor's application.

Finally, staff proposed that a distributor's application to the Board requesting rate relief for incremental CAPEX during IR include the following:

- An analysis demonstrating that the threshold test has been met and that the amounts will have a significant influence on the operation of the distributor;

- A description of the underlying causes and timing of the capital expenditures, including an indication of whether expenditure levels could trigger a further application before the end of the IR term;
- An analysis of the revenue requirement associated with the capital spending (i.e., the incremental depreciation, return on rate base and payments in lieu of taxes ("PILs") associated with the incremental capital), and a specific proposal as to the amount of rate relief sought;
- Justification that the impact on revenue required is incremental to what was included in the application for the base year. Amounts being sought should be directly related to the claimed cause, which must be clearly non-discretionary and clearly outside of the base upon which current rates were derived;
- Justification that the amounts to be incurred will be prudent. This means that the distributor's decision to incur the amounts represents the most cost-effective option (not necessarily least initial cost) for ratepayers;
- Evidence that the incremental revenue requested will not be recovered through other means (e.g., it is not being funded by the expansion of service to include new customers); and
- A description of the actions the distributor will take in the event that the Board does not approve the application.

General Comments

In general, distributors initially expressed a preference for a multi-year capital plan review and approval approach in addition to the availability of a capital investment module. Some distributors maintained that the issue of unfunded capital arises when a distributor has to undertake programs or projects to meet requirements that may be in excess of what is allowed in the price cap formula, which implicitly considers a steady state growth rate in depreciation and returns, based on the historical costs of capital, and capital expenditures that are in effect equal to that annual depreciation expense. While these distributors were supportive of moving forward with a comprehensive price cap for 3rd Generation IR and were not advocating that distributors be held "whole" during the term for all capital expenditures, some distributors did advocate that distributors have a reasonable expectation of achieving their approved returns without being unduly penalized by having to significantly reduce their OM&A and/or capital programs. While some distributors expressed concern about the magnitude of the threshold in staff's revised proposal, they commented that the form of the mechanism is a major step forward in recognizing the business drivers necessitating such a module.

Participants representing groups of ratepayers generally expressed concern that staff's proposed approach may over-compensate distributors and result in over-earning during the IR term without clear requisite benefits to ratepayers. Many of these participants commented that CAPEX will be addressed in rebasing prior to IR, and they cautioned that any approach implemented with a capital module should only deal with incremental needs and that applications should have to include comprehensive evidence to support the claim.

One participant recommended that module treatment of capital investment should only be extended to two categories of "need" (lumpy spending and spending to improve productivity) and only to the amount that is not captured through the basic "inflation minus productivity" indexing rate adjustment components.

Another participant commented that the IR plan term should be three years to help reduce potential need for some form of special treatment of materially significant investment. This participant acknowledged that, to the extent that distributors find during the term of the IR plan that the formula is not sufficient to support incremental capital expenditures, they should have an opportunity to apply for the Board for relief; however, the onus would be on the distributor to demonstrate why its rates, derived using the formula, would not be sufficient to support the incremental capital investment. Under a three-year plan, this participant noted, such requests would be the exception, and not the norm.

A third participant urged the Board not to include an incremental capital module, and noted that PEG clearly indicated that there is no need for any explicit adjustment for capital in the indexing mechanism just because rate base is growing. This participant suggested that, if a distributor believes that it has significant incremental capital needs, the distributor should be encouraged to make a cost of service or multiple year cost of service filing. This participant also recommended that, if distributors are allowed to invoke the incremental capital module, then the X-factor proposed by PEG should be increased significantly to reflect that a significant amount of the capital has been removed from a comprehensive incentive rate mechanism, leaving a partial mechanism. Finally, if incremental capital is approved in rates, this participant expressed the view that distributors cannot expect to retain any excess earnings that they may achieve over and above that level.

Comments on Scope

One participant representing a group of ratepayers commented that the Board should not allow incremental rates where, for example, a distributor seeks to capitalize more of the costs of its existing labour force, or where a distributor says that its input costs for poles have gone up faster than inflation, or where a distributor says that it wants to prepare for future growth patterns, because these are all capital spending issues that should be handled within, and not outside of, the price cap budget provided.

Comments on the Materiality Threshold

In response to staff's proposed 25% of capital budget threshold, distributors commented that linking an incremental capital module to a capital budget may be problematic because the base year capital budget is likely to vary significantly among distributors for a variety of reasons. They also commented that capital budgets could be distorted and/or not representative of future investment trends depending on investment cycles, the lumpiness of certain types of investments, and similar factors. Two participants commented that with the 25% of capital budget threshold the module could also be triggered even if rate base is declining (i.e., capital expenditures are less than depreciation expense).

Commenting that the proposed application requirements appear acceptable and not excessive, one distributor commented that the 150% depreciation threshold is appropriate and will address the most serious cases. However, some distributors, agreeing in general with the application requirements, commented that 150% depreciation is too high, and proposed the use of 125% above the depreciation expense from the approved base year. Another participant commented that the threshold of 150% may underestimate the degree of hardship for some, and encouraged the Board to allow applications for incremental CAPEX that will have significant influence on operations, regardless of the amounts.

One participant representing a group of ratepayers commented that the 150% of depreciation threshold is an improvement over the 25% of capital budget threshold. However, this participant expressed concern that, depending on what amount would actually be recovered through the module and subsequently what level of depreciation expense becomes the new benchmark for the threshold test, distributors may be encouraged to over spend on capital expenditures or accelerate their capital spending if they are near the threshold in order to use the module to increase revenue. This participant proposed that, if at the end of the IR term the actual CAPEX to depreciation ratio falls below 150%, any revenues collected through the application of the incremental capital module should be rebated to customers (with appropriate interest).

Another participant representing a different group of ratepayers commented that the use of an average is an improvement over staff's original proposal, but cautioned that it can still lead to perverse results with regard to the timing of expenditures (i.e., re-adjusting forecasted capital needs to be eligible for the module sooner). This participant recommended that application requirements include sufficient information to test this issue.

Commenting that the proposed 150% depreciation is too low, a fourth participant representing another group of ratepayers demonstrated the relationship between annual capital spending (affected by inflation) and the base depreciation levels already built into rate base. For example, this participant commented, for a distributor with zero growth (and therefore constant real dollar capital spending), at a 2% inflation rate (i.e., the Bank of Canada target inflation rate) and a 3.9% average depreciation rate (the current Ontario norm), the price cap mechanism naturally provides for capital spending of 150% of depreciation or more; and where a distributor has growth, it will have available, without any special treatment, substantially more than the 150% level. This participant expressed the belief that the threshold has to be at least 20% higher than the CAPEX spending provided for naturally by the price cap regime. Further, this participant stated that it is possible to estimate the amount of CAPEX generally allowed for by the price cap, tracked to growth rates, and thus to create a simple threshold formula that depends only on the approved depreciation level, and the distributor's growth rate.

Comments on Implementation Issues

While participants generally expressed a relatively common understanding of the overall intent of the capital module and how it might be implemented, they differed on views with regard to details.

Some distributors proposed specific considerations for implementation of a capital module that were generally consistent with staff's revised proposal, with the exception of a lower materiality threshold (125% depreciation included in base rates). Also, these distributors suggested that while they agreed that annual reporting on actual spend would be appropriate, no true-up would be required for the IR term unless there was evidence that there was a serious overstatement of capital requirements. In contrast, a participant representing a group of ratepayers noted that the application of the module would be based on forecast capital expenditures from the distributors and therefore a true-up should be used to reflect differences between the actual and forecast amounts, particularly if the actual expenditures, for whatever reason, do not hit the 150%

materiality threshold that they were forecast to hit. Two other participants commented that if an application addresses more than one year (looking forward) then forecasting accuracy (in terms of both capital spending and customer load) as well as the potential for variances between forecast and actual spending amounts become more significant matters and there is an increased need for ratepayer protection.

To mitigate the potential for unintended results with regard to the timing of expenditures, another participant recommended that, in addition to what was already identified in staff's revised proposal, the application requirements should also include a requirement that the distributor do the following: demonstrate that the incremental revenue requirement impact is not covered by the IR mechanism through the provision of forecasts for customer count, volumes and associated revenue, and revenue requirement associated with existing and proposed capital; and calculate the "rate adder" associated with the incremental revenue requirement. Another participant expressed support for a deferral account approach, consistent with the current mechanism in place to deal with smart meter expenditures, with amounts subject to a true-up upon rebasing based on the actual amounts spent. This participant noted that this could be captured through a rate rider rather than an adjustment to rates.

Policy and Rationale

The Board has determined that there will be an incremental capital module in 3rd Generation IR. Distributors with an amount of capital spending that exceeds the materiality threshold may best be accommodated through rebasing. However, on balance, as all participants acknowledged, some incremental capital investment needs may arise during the IR term and the Board notes that a clearly defined modular approach is generally accepted.

The incremental capital module described in this report is intended to address concerns over the treatment of incremental capital investment needs that may arise during the IR term.

While the module may provide for a broad scope for incremental capital needs, specific application must be made to provide for review and approval of stated need. Applications must be accompanied by comprehensive evidence to support the claimed need. The Board considers that the application requirements proposed by staff are reasonable.

For incremental capital expenditures to be considered for recovery prior to rebasing, amounts must satisfy the eligibility criteria set out in Table 5.

Table 5: Incremental Capital Investment Eligibility Criteria

Criteria	Description
Materiality	The amounts must exceed the Board-defined materiality threshold and clearly have a significant influence on the operation of the distributor; otherwise they should be dealt with at rebasing.
Need	Amounts should be directly related to the claimed driver, which must be clearly non-discretionary. The amounts must be clearly outside of the base upon which rates were derived.
Prudence	The amounts to be incurred must be prudent. This means that the distributor's decision to incur the amounts must represent the most cost-effective option (not necessarily least initial cost) for ratepayers.

As noted in the above table, **eligibility of a distributor to apply for rate relief through the module will be subject to a materiality threshold**. **However, the Board would be assisted by further consultation on the appropriate materiality threshold. The issue of the appropriate materiality threshold will therefore be included on the agenda for the August stakeholder conference (see Section 5).**

The Board has also determined that there will be annual reporting on actual capital spending and a prudence review at the time of rebasing. Distributors that receive rate relief through this module will be required to report to the Board annually on the actual amounts spent. At the time of rebasing, the Board will carry out a prudence review to determine the amounts to be incorporated in rate base. The Board will also make a determination at that time regarding the treatment of differences between forecast and the actual spending during the IR plan term. If the forecast costs

exceeded actual amounts spent, the difference will be returned to ratepayers. Cost overruns will be reviewed at the time of rebasing.
The Board agrees with the comments of all participants that capital expenditures mandated through government policy (e.g., smart meters) should continue to be dealt with outside of the IR plan.

With the exception of the value of the materiality threshold, the Appendix outlines the detailed requirements as they apply to 3rd Generation IR.

2.6 Treatment of Unforeseen Events

Z-factors are intended to provide for unforeseen events outside of management's control, and are a common feature of IR plans. In general, the cost to a distributor of these events must be material and its cost causation clear.

Issues and Options Raised in Consultation

The Discussion Paper acknowledged a number of issues related to Z-factor claims by electricity distributors, including the general view of distributors and other stakeholders that the current materiality thresholds are too low. The Discussion Paper identified the option of raising the two existing materiality thresholds for expenses and capital costs from the current 0.2 percent to 3 percent. During the May 6, 2008 stakeholder meeting, and in response to participant comments as summarized below, staff proposed the continuation of the current rules, with the exception of the scope of events that would qualify for Z-factor treatment and of the materiality threshold, and put forward a single threshold of 0.5 percent on total revenue requirement.

For 2nd Generation IR, Z-factors are limited to natural disasters and tax changes. One distributor questioned whether Z-factors need to be this limited. This distributor expressed the view that the eligibility criteria and the application filing, review and approval process requirements are adequate to discourage applications for relatively nominal amounts. Arguing that a specific materiality threshold is not needed, this distributor noted that the attention the Board, staff and intervenors give to a claim in an application would be proportionate to their respective concerns regarding the appropriateness and materiality of the claim.

As noted previously, some participants expressed concern over the issue of the treatment of tax changes under an IR plan that uses the GDP IPI FDD.

Some distributors recommended that the Board hold a consultation on the appropriate materiality threshold level and rules governing a Z-factor adjustment rather than applying an arbitrary 3% threshold level.

All participants representing ratepayer groups generally concurred that a single threshold which is indifferent to the type of costs incurred may be the most practical approach and that 0.5% of the total revenue requirement is reasonable. Further, they noted that this should apply to each event and not be a cumulative amount.

While generally agreeing with a move to a single threshold measure, another participant proposed refinements to the threshold test to address distributor diversity. This participant noted that, whatever formula is used to assess materiality, the actual dollar values for each distributor may not make sense if the distributor is very small or very large. Therefore, this participant proposed that for a distributor with a revenue requirement over $200 million the threshold would be fixed at $2 million, and for a distributor with a revenue requirement below $10 million the threshold would be fixed at $100,000.

Policy and Rationale

The Board has determined that the eligibility criteria are sufficient to limit Z-factors to events genuinely external to the regulatory regime and beyond the control of management and the Board.

With regard to the issue of tax changes, the Board will be informed by the decision in the EB-2007-0606/615 proceeding in relation to gas distributor incentive regulation applications in which tax as a Z-factor is being considered. The Board will provide further guidance to electricity distributors subsequent to issuance of that decision.

The Board believes that a materiality threshold is important to provide distributors with guidance as to whether or not they should be applying to the Board for relief from a Z-factor event. **The Board has decided to set the materiality threshold based on the distributor's revenue requirement**.

Setting a single threshold of 0.5% of total revenue requirement may not make sense if a distributor is very small or very large. Staff's analysis presented at the May 6th stakeholder meeting indicated that staff's proposal would result in inordinately low threshold amounts for some small distributors (e.g., $1,600 for a distributor with a revenue requirement of $320,000) and inordinately high threshold amounts for some large distributors (e.g., over $2 million for a distributor with a revenue requirement of $525 million). Therefore, **the materiality threshold will be differentiated based on the relative magnitude of the revenue requirement** in order to maintain the concept of relative materiality across diverse distributors. Specifically, the materiality threshold will be as follows:

- $50 thousand for distributors with a distribution revenue requirement less than or equal to $10 million;
- 0.5% of distribution revenue requirement for distributors with a revenue requirement greater than $10 million and less than or equal to $200 million; and
- $1 million for distributors with a distribution revenue requirement of more than $200 million.

As is currently the case, the threshold must be met on an individual event basis in order to be eligible for potential recovery.

Distributors are expected to report events to the Board promptly and apply to the Board for any amounts claimed under Z-factor treatment with the next rate application. This will permit the Board and any affected distributor to address extraordinary events in a timely manner. Subsequently, the Board may review and prospectively adjust the amounts claimed under Z-factor treatment.

The Board expects that any application for a Z-factor will be accompanied by a clear demonstration that the management of the distributor could not have been able to plan and budget for the event and that the harm caused by extraordinary events is genuinely incremental to their experience or reasonable expectations.

The Appendix outlines the detailed requirements as they apply to 3rd Generation IR.

2.7 Off-ramps

An off-ramp is based on a pre-defined set of conditions under which the IR plan would be terminated or modified before its normal end-of-term date, usually because of extreme events that cannot be effectively addressed, or that should not be addressed, through Z-factor treatment or some other IR mechanism such as earnings sharing.

For the 2nd Generation IR mechanism, there are limited adjustments available to distributors. Therefore, an off-ramp is available where these adjustments proved insufficient for specific cost pressures (e.g., additional capital investment). Where this is the case, distributors are expected to file a comprehensive cost of service application and not to rely on the simplified filing requirements for the incentive mechanism.

Issues and Options Raised in Consultation

The Discussion Paper invited comment on a pre-defined off-ramp associated with excessive over or under earnings. At the May 6, 2008 stakeholder meeting, and in response to participant comments received as summarized below, staff proposed a less prescriptive approach in which a review may be initiated on a case-by-case basis on application.

While some participants supported the pre-defined off-ramp associated with excessive over or under earnings, others expressed the view that the use of off-ramps should be determined on a case-by-case basis where a distributor brings forward an application.

Some distributors recommended that the use of off-ramps be determined on a case-by-case basis where a distributor brings forward an application that proposes modifications to the adjustment mechanism or where the distributor is seeking a cost of service rebasing. One participant representing a ratepayer group also suggested that the distributor, its ratepayers, or Board staff should be able to invoke an off-ramp, and that the goal of providing for the off-ramp application should be to ensure that the IR plan and the distributor's circumstances are reviewed, not necessarily changed. In response, another participant stated it could not support this proposal because intervenors do not have access to the timely and detailed information needed to determine if a distributor should be compelled to come before the Board and explain why the IR plan should be terminated or continued.

Policy and Rationale

The Board has determined that the 3rd Generation IR plan will include a trigger mechanism with an **annual ROE dead band of ±300 basis points. When a distributor performs outside of this earnings dead band, a regulatory review may be initiated**. In support of this approach, a distributor will be required make a report to the Board no later than 60 days after the company's receipt of its annual audited financial statements, in the event that the distributor falls short of or exceeds its ROE by 300 basis points. The report will be reviewed to determine if further action by the Board is warranted. Any such review would be prospective and could result in modifications to the IR plan, a termination of the IR plan or the continuation of the IR plan.

The Board believes this to be appropriate because of the uncertainty associated the various components of an IR plan. The Board intends this to be an early warning mechanism rather than necessarily terminating the IR plan, although that could be the outcome of any subsequent review.

The Board notes that most participants representing groups of ratepayers supported a pre-defined earnings-based off-ramp, especially in the absence of an earnings sharing mechanism. Several of these participants proposed an off-ramp as described above and which is similar to that agreed to in the settlements accepted in the two recent gas IR proceedings.

Implementation

The Board agrees that effective implementation of a prescriptive off-ramp will require timely release of distributor performance and financial data. Reporting requirements and review processes will be developed to support this mechanism.

2.8 Earnings Sharing

An earnings sharing mechanism ("ESM") provides ratepayers protection to the extent there is some level of uncertainty in the IR plan parameters. In addition, to the extent that a distributor is able to achieve significant efficiency gains during the IR plan period, it allows for ratepayers to share in those gains.

Issues and Options Raised in Consultation

Staff's Discussion Paper invited comments from participants on whether an ESM should be part of 3rd Generation IR and, if so, whether an asymmetrical ESM might be appropriate.

In light of comments received, as summarized below, staff proposed an asymmetrical mechanism during the May 6, 2008 stakeholder meeting. Under the proposal, amounts would be recorded each year during the IR plan term if a distributor's actual non-weather normalized earnings exceeded the calculated ROE by 200 basis points,[2] and would be shared equally (i.e., 50:50) at the time of rebasing. This proposal was intended to respond to the views expressed by various participants that certain elements of staff's composite proposal for the 3rd Generation IR framework may benefit from the counter-balance of an ESM. Specifically: the distributor's access to an incremental capital module; uncertainty associated with the estimation of the input price differential and productivity differential to implement in conjunction with the GDP IPI FDD; and some uncertainty in relation to the setting of appropriate stretch factors. This proposal was also based on a four year IR plan term.

Participants representing ratepayer groups continued to express strong support for earnings sharing. They commented that ratepayers do not have access to full information regarding a distributor's financial results and do not have the same ability as distributors to seek Z-factor relief. As such, they commented that the use of an ESM would provide a level of ratepayer protection during the IR plan. In general, these participants commented that ESM benefits should be shared annually, not at the time of rebasing. Another participant expressed the view that an ESM is an important component of any IR plan and that, to the extent that the Board were to decide to allow

[2] ROE would be recalculated annually based on that year's application of the ROE formula and earnings sharing would be calculated as +200 basis points from that number.

for five year terms, an ESM would be an essential component of the IR plan. This participant expressed support for an asymmetrical earnings sharing mechanism given the fact that distributors can opt out of the IR plan at any point and apply for rates based on cost of service, and specifically proposed that if the term is five years the dead band should be 100 basis points and if the term is three years the dead band should be 200 basis points.

Two participants proposed menu approaches to the ESM that would be tied to the selection of productivity and/or stretch factors.

Another participant representing a ratepayer group, generally opposed to earnings sharing in IR plans, expressed the belief that an ESM is appropriate in 3rd Generation IR, and suggested that the asymmetrical ESM recently implemented for one of the gas distributors based on actual earnings and with a 200 basis point dead band, would be appropriate. However, this participant expressed the expectation that the need for an ESM could be reduced or eliminated in the next generation of IR for electricity distributors.

Some distributors commented that ESMs have the undesirable feature that they reduce the power of incentives for efficiency improvements, and cautioned that in considering such mechanisms, one should be mindful that, upon rebasing, consumers capture the benefits of efficiency improvements in perpetuity. This participant noted that, in the event that an ESM were to be implemented, it should be symmetrical and amounts should be cumulative over the term of the IR plan.

One participant commented that the need for an ESM, or an off-ramp for that matter, is very much dependent on the robustness of the IR mechanism. This participant provided as an example the critical short comings of the use of OM&A rather than total cost benchmarking in the application of the stretch factors. If the Board were to adopt this approach, this participant's view was that an ESM and an off-ramp would be required to mitigate the risk associated with this approach.

Some distributors commented that they accept the use of ESMs in IR plans that are in effect for more than five years, and recommended that under such plans if the achieved ROE from regulated activities was more than 300 basis points different from the Board's allowed ROE, then the computed overage/underage should be shared equally (i.e., 50:50) between the distributor and its ratepayers.

Policy and Rationale

The Board will not implement an ESM for 3rd Generation IR.

The Board has determined a relatively short plan term of three years for the 3rd Generation IR plan. During those three years, the IR plan will include an industry productivity factor as well as a stretch factor. Implicit in these factors are expected benefits that are shared with ratepayers, up-front throughout the IR term. In contrast, the ESM is designed to share benefits after-the-fact. This premise, supported by many participant comments, suggests that the only function of the ESM is a "safety net" should the productivity and stretch factors be too low. However, with a short plan term and confidence in these factors, the need for a safety net is largely reduced.

The Board is of the view that monitoring and reporting will capture any instances of a distributor earning super-normal profits. In such cases, a regulatory review, and potential off-ramp, can be triggered.

The Board also has concerns over the implementation of an ESM. The regulatory burden that this would place on distributors, intervenors, and the Board is significant. Once the framework for the over earnings calculations is established, the filings by the distributors would have to be tested for accuracy and prudence.

Therefore, in light of the short IR plan term, the availability of an off-ramp and the consumer benefit in the form of productivity and stretch factors for 3rd Generation IR, the Board has determined not to implement an ESM.

2.9 Service Quality

When the Board launched the Rate Plan, it also committed to implementing a regime of service quality requirements which would work to ensure that consumers continue to receive a high level of service from their distributors during the term of an IR plan.

On June 4, 2008, the Board issued amendments to the Distribution System Code which established a set of customer related service quality requirements with associated performance standards. These requirements include four previous service quality indicators (Connection of New Services, Appointments Met, Telephone Accessibility, and Written Response to Enquiries) and three new requirements (Appointment Scheduling, Rescheduling a Missed Appointment and Telephone Call Abandon Rate).

These service quality requirements and associated performance standards will come into effect in January 2009.

For the time being, the three existing system reliability indicators (SAIDI, SAIFI & CAIDI) will continue as reporting requirements. However, the Board's expectation is that system reliability requirements will eventually become mandatory.

2.10 Reporting Requirements

Reporting requirements and review processes will be developed as required to support the elements of the 3rd Generation IR mechanism that are described in this report.

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3 Implementation

A participant representing a group of ratepayers, building on a proposal by one of the distributors, recommended that in each rate order on rebasing, the Board panel structure the order so that annual adjustments, consistent with the IR plan as applied to that particular distributor, are included as part of the order. According to this participant, this approach could accomplish two things: first, where the Board accepts custom values based on specific application for any of the parameters in the IR plan, this approach would create a method by which that decision could be implemented; and second, it would also set the rates for each year of the IR plan term through a proper hearing on an evidentiary basis and any subsequent application by the distributor to re-open any of those years would be a reconsideration of the existing order (requiring an application to vary the existing order), not a fresh application. The Board sees merit in this suggestion and will give it further consideration.

3.1 How Adjustments Would be Determined

3.1.1 Continued Migration to Common Capital Structure

The Board will continue to include an adjustment to rates in 2009 and 2010 where applicable as outlined in its December 20, 2006 "Report of the Board on Cost of Capital and 2nd Generation IR for Ontario's Electricity Distributors", in order to transition distributors to the single deemed capital structure of 60% debt and 40% equity.

3.1.2 Conservation and Demand Management

The Discussion Paper noted that staff and the working group generally felt that the current Lost Revenue Adjustment Mechanism ("LRAM") is appropriate until the completion of the consultations on rate design for electricity distributors since those consultations will look at related issues. The Discussion Paper invited comment on a revenue stabilization adjustment mechanism (“RSAM”), on a model that would include a CDM adjustment factor based on the CDM targets set by the Government of Ontario and/or the Ontario Power Authority, and on the option of maintaining the status quo vis-à-vis the Board’s current LRAM and shared savings mechanism (“SSM”) for electricity distributors.

Issues and Options Raised in Consultation

Most participants supported the continuation of the current LRAM and SSM. Some participants commented that a RSAM would involve a significant change in the risk profile of electricity distributors and/or their allowed return on equity, would require the production of load forecasts, and would shift the risk of volume fluctuations and deviations from forecast from the distributor to the ratepayers. In addition, alternative mechanisms do not appear to be practical at this point in time. One participant suggested that, going forward, if there is evidence that revenue erosion during the term of an IR plan is increasing, adjustment mechanisms may then be considered by the Board. As such, this participant concluded, this could be part of a longer term framework.

Distributors commented that they believed that in the short term distributors can make use of the existing lost revenue adjustment processes and that revenue-oriented IR alternatives could accommodate broader concerns around reductions in load and customer numbers.

Policy and Rationale

On March 28, 2008, the Board issued its “Guidelines for Electricity Distributor Conservation and Demand Management” which consolidate all of the Board’s policies in relation to CDM activities undertaken by electricity distributors. In those guidelines, the

Board noted that whether and how CDM funding may be included in the IR mechanism rate adjustment would be addressed in the appropriate forum.

As a result of these 3rd Generation IR consultations, the Board has determined that **CDM-related costs recovered through distribution rates (i.e., any new spending on CDM, revenues from recovery of a lost revenue adjustment claim, or a shared savings claim) will continue to be dealt with separately from the IR rate adjustment**.

This represents the status quo. The Board acknowledges that, should alternatives to the status quo be examined, these could have implications for electricity distributors and ratepayers. In the Board's view, these would best be dealt with as part of the consultations on rate design for electricity distributors (consultation EB-2007-0031).

3.1.3 Deferral and Variance Accounts

A set of authorized variance / deferral accounts are identified in the Board's Accounting Procedures Handbook. In its December 20, 2006 "Report of the Board on Cost of Capital and 2nd Generation IR for Ontario's Electricity Distributors", the Board indicated that, to the extent possible, it will limit reliance on the creation of new deferral accounts during the term of the 2nd Generation IR plan to well-defined and well-justified cases only. The Board will continue this practice for purposes of the 3rd Generation IR plan.

With respect to the disposition of commodity deferral and variance accounts, the Board is required to make an order at least every three months to determine whether and how the amounts recorded in such accounts (currently recorded in Account 1588 of the Uniform System of Accounts) shall be reflected in rates. With respect to non-commodity deferral or variance accounts, the Board is required to make an order at least annually.

In a letter dated February 19, 2008, the Board notified electricity distributors and other interested stakeholders that it intends to launch an initiative to develop policies and processes for the review and disposition of Account 1588. The Board indicated that it will consider the use of account disposition thresholds or “disposition triggers”. The Board also stated that it will consider whether to extend this initiative to deferral or variance accounts that are similar in nature to Account 1588, such as the Retail Settlement Variance Accounts (RSVAs) and the Retail Cost Variance Accounts (RCVAs).

The Board therefore expects distributors to deal with deferral and variance account disposition outside of the IR rate adjustment.

3.1.4 Adjustments to Revenue-to-Cost Ratios

On November 28, 2007, the Board released a report on the “Application of Cost Allocation for Electricity Distributors” which outlines the Board’s expectations on how electricity distributors are to adjust the revenue-to-costs ratios to bring them within the ranges stated in the report.

The cost allocation policies reflected in that report are to be followed by distributors whenever they apply for rates on a cost of service basis. In the event that further adjustments to one or more revenue to cost ratios have been specified by a prior Board Decision, then base rates will need to be adjusted accordingly prior to the application of the price cap index.

3.1.5 Application of the Price Cap Index

Consistent with the 1st Generation IR and the 2nd Generation IR mechanisms, the 3rd Generation IR price cap index will be applied uniformly across all customer classes and to both the Service Charge and the Distribution Volumetric Rate (including low voltage charges for embedded distributors), net of existing rate adders and rate rebalancing adjustments as determined necessary by the Board.

The Board has determined that a distributor's allowance for taxes will continue to be adjusted by the price cap index. A distributor's allowance for taxes (whether PILs or actual taxes) currently includes provision for income tax and the Ontario capital tax. The Board does not think the tax allowance should be shielded from the index. This allowance should escalate in line with the other components of the revenue requirement reflected in base rates. As discussed in Section 2.6, the Board will in due course provide further guidance on the issue of treatment of material changes in tax rules during 3rd Generation IR.

The Board has determined that smart meter related matters **will continue to be dealt with separately from the IR rate adjustment and that the guidelines included in the Addendum will continue to apply.**

Also, consistent with practice to date in Ontario, the index will not be applied to specific service charges. The Board carried out a generic review on specific service charges in 2005,[3] and is currently carrying out further related consultations in respect of the provision of specific services and the application of associated charges (consultation EB-2007-0722). Until this work is complete, **the Board expects distributors to continue to use the currently established specific service charges and to deal with the need for new specific service charges outside of the IR rate adjustment.**

The price cap adjustment will not be applied to Rate Riders, Retail Transmission Service Rates, Wholesale Market Service Rate, Rural Rate Protection Charge, Standard Supply Service – Administrative Charge, Allowances[4], Retail Service Charges or Loss Factors.

[3] See chapter 11 of the 2006 Electricity Distribution Rate Handbook.
[4] Transformation and primary metering allowances and any other allowances the Board may determine.

A “de-construction” of 2008 rates will be carried out prior to adjusting base rates. After adjusting base rates with the price cap index, rate elements will be “re-constructed” to derive 2009 rates.

3.2 Rebasing Rules

Rebasing at the end of 3rd Generation IR will be based on a cost of service filing. Benchmarking evidence may be used within the scope of the cost of service proceeding.

Under the existing cost of service filing requirements, distributors are required to provide a detailed variance analysis between the Test Year and Bridge Year, and between the Test Year, the Historical Year and the last Board-approved Test Year. In response to concerns raised by distributors that significant upward pressure is anticipated on capital expenditures, the Board has determined that the distributor will be required to provide historical plant continuity information for each year of the IR plan term since the last Board-approved Test Year, and will revise the filing requirements accordingly. This information will inform the Board’s review and approval of the distributor’s rebasing application and the determination of appropriate capital expenditure levels for inclusion in base rates going forward.

4 Summary

The Board engaged many interested stakeholders in the discussion of an appropriate 3rd Generation IR for electricity distributors. This consultation has assisted the Board in developing the policies detailed in this report. The Board has appreciated the input from all stakeholders in determining the approach it should take. The Board has been particularly encouraged by the productive dialogue among the experts hired by the various participants.

The rate adjustments for the 2009 rate year will apply to distributors that were subject to rate rebasing in 2008. Distributors that have not yet applied for, or been subject to, rebasing, will continue to be subject to the 2nd Generation IR. For the 2010 and 2011 rate years the policy will continue to apply to the distributors whose rates were rebased in 2008 and will also apply to the additional distributors whose rates have been subject to rebasing in 2009 and 2010. The 3rd Generation IR mechanism elements are summarized in the following table.

Table 6: Components of the Board's 3rd Generation IR Policy

Inflation Factor	• Canada GDP IPI for final domestic demand – updated annually in March. Until Ontario data used to derive total factor productivity trend, values for the input price differential and productivity differential will be zero.
Productivity Factor	• Fixed at industry total factor productivity trend percentage per year for term of plan – all distributors subject to the same value.
Stretch Factors	• Differentiated based on distributor efficiency – updated annually in July. • Distributors will be assigned to 1 of 3 groups with stretch factors based on their efficiency as determined through comparative cost analysis.
Z-factors	• Will be on application (by next rate filing) subject to the three criteria of causation, materiality and prudence.
Incremental Capital	• Will be on application subject to the three criteria of materiality, need and prudence.

The Board will consider work to refine its empirical work on the electricity distribution sector, including total cost benchmarking, an Ontario TFP study, and input price trend research, in the context of its overall business planning process.

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5 Topics for Presentations at the Conference

This report sets out the Board's policies and approach to 3rd Generation IR and presents guidelines that the Board expects distributors to use in preparing their rate applications. This report also identifies three outstanding matters where the Board's determination may benefit from further consultation.

On June 13, 2008, the Board notified participants of a stakeholder conference that will be held the week of August 5, 2008. The August stakeholder conference will provide a forum for further discussion of the appropriate values for the productivity factor, the stretch factor, and the capital module materiality threshold. The Board will not entertain comments on any other issue at the conference.

The Board would be assisted by participants addressing the following questions in their presentations at the conference.

Productivity Factor

- What is the appropriate value for TFP trend?

Stretch Factor

- What are appropriate stretch factor values for each of the three groups?

Incremental Capital Module

- What is an appropriate capital expenditure to depreciation threshold value to determine materiality?

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Appendix: Filing Guidelines

These filing guidelines set out the Board's expectations for applications by distributors for rate adjustments on the basis of the 3rd Generation IR mechanism as set out in this report.

General

The implementation of the 3rd Generation IR mechanism will occur first with rate adjustments scheduled for May 1, 2009.

The price cap adjustment will be applied to the Service Charge and Distribution Volumetric Rate (including low voltage charges for embedded distributors), net of existing rate adders and rate rebalancing adjustments as determined necessary by the Board. The price cap adjustment will not be applied to Rate Riders, Retail Transmission Service Rates, Wholesale Market Service Rate, Rural Rate Protection Charge, Standard Supply Service – Administrative Charge, Specific Service Charges, Allowances[5], Retail Service Charges or Loss Factors.

The price cap adjustment will reflect inflation less the X-factor, and an adjustment for the transition to the common deemed capital structure of 60% debt and 40% equity.

[5] Transformation and primary metering allowances and any other allowances the Board may determine.

Manager's Summary

Each application should include a completed Model and a brief Manager's Summary explaining all rate adjustments applied for. Any deviations should be thoroughly documented. Where necessary, support for applied adjustments, such as continuation of rate riders or for Z-factors, should be provided.

Incremental Capital Module

The incremental capital module has been incorporated into the 3rd Generation IR mechanism to address the treatment of incremental capital investment needs that arise during the IR plan term.

Eligibility Criteria for Incremental Capital Module Applications

The eligibility criteria for applications to recover amounts through rates to fund incremental capital investment needs are discussed in section 2.5 of this report, and are reproduced in Table 7 below for convenience:

Table 7: Incremental Capital Investment Eligibility Criteria

Criteria	Description
Materiality	The amounts must exceed the Board-defined materiality threshold and clearly have a significant influence on the operation of the distributor; otherwise they should be dealt with at rebasing.
Need	Amounts should be directly related to the claimed driver, which must be clearly non-discretionary. The amounts must be clearly outside of the base upon which rates were derived.
Prudence	The amounts to be incurred must be prudent. This means that the distributor's decision to incur the amounts must represent the most cost-effective option (not necessarily least initial cost) for ratepayers.

Materiality Threshold

To be determined by the Board.

Filing Guidelines

The Board expects that applications requesting relief for incremental CAPEX during the IR plan term will be accompanied by comprehensive evidence to support the claimed need, and include the following:

- An analysis demonstrating that the materiality threshold test has been met and that the amounts will have a significant influence on the operation of the distributor;
- A description of the underlying causes and timing of the capital expenditures including an indication of whether expenditure levels could trigger a further application before the end of the IR term;
- An analysis of the revenue requirement associated with the capital spending (i.e., the incremental depreciation, OM&A, return on rate base and PILs associated with the incremental capital), and a specific proposal as to the amount of relief sought;
- Justification that amounts being sought are directly related to the claimed cause, which must be clearly non-discretionary and clearly outside of the base upon which current rates were been derived;
- Justification that the amounts to be incurred will be prudent. This means that the distributor's decision to incur the amounts represents the most cost-effective option (not necessarily least initial cost) for ratepayers;
- Evidence that the incremental revenue requested will not be recovered through other means (e.g., it is not, in full or in part, included in base rates or being funded by the expansion of service to include new customers); and
- A description of the actions the distributor will take in the event that the Board does not approve the application.

Reporting Requirements

Distributors that receive rate relief through this module will be required to report to the Board annually on the actual amounts spent. At the time of rebasing, the Board will carry out a prudence review to determine the amounts to be incorporated in rate base. The Board will also make a determination at that time regarding the treatment of differences between forecast and actual capital spending during the IR plan term. If the forecast costs exceeded actual amounts spent, the difference should be returned to ratepayers. Cost overruns will be reviewed at the time of rebasing.

Z-Factors

Z-factors are events that are not within management's control. A distributor will be expected to supply the details of management's plans for addressing these events in support of the distributor's request for special cost recovery.

A distributor may record amounts which meet the eligibility criteria presented below for Z-factor events.

A distributor is expected to follow the guidelines listed below when applying to the Board to recover from ratepayers the amounts that the distributor has recorded. The Board may limit the recovery of certain amounts.

Eligibility Criteria for Z-factor Amounts

The eligibility criteria for applications to recover amounts in the Z-factor are discussed in section 2.6 of this report, and are summarized inTable 8 below. In order for amounts to be considered for recovery in the Z-factor, the amounts must satisfy all three criteria set out in Table 8.

Table 8: Z-Factor Amount Eligibility Criteria

Criteria	Description
Causation	Amounts should be directly related to the Z-factor event. The amount must be clearly outside of the base upon which rates were derived.
Materiality	The amounts must exceed the Board-defined materiality threshold and have a significant influence on the operation of the distributor; otherwise they should be expensed in the normal course and addressed through organizational productivity improvements.
Prudence	The amount must have been prudently incurred. This means that the distributor's decision to incur the amount must represent the most cost-effective option (not necessarily least initial cost) for ratepayers.

Materiality Threshold

The Board has determined that the following materiality thresholds will apply:

- $50 thousand for distributors with a distribution revenue requirement less than or equal to $10 million;
- 0.5% of distribution revenue requirement for distributors with a revenue requirement greater than $10 million and less than or equal to $200 million; and
- $1 million for distributors with a distribution revenue requirement of more than $200 million.

As is currently the case, the threshold must be met on an individual event basis in order to be eligible for potential recovery.

Filing Guidelines

Distributors are expected to submit evidence that the costs/revenues which were incurred / received meet the three eligibility criteria outlined above.

Distributors are expected to report events to the Board promptly and apply to the Board for any amounts claimed under Z-factor treatment with the next rate application. This will allow the Board and any affected distributor the flexibility to address extraordinary events in a timely manner. Subsequently, the Board may review and prospectively adjust the amounts claimed under Z-factor treatment.

The Board expects that any application for a Z-factor will be accompanied by a clear demonstration that the management of the distributor could not have been able to plan and budget for the event and that the harm caused by extraordinary events is genuinely incremental to their experience or reasonable expectations.

Other Matters in Relation to Z-Factors and Incremental Capital Module

Distributors will be expected to file a proposal, including the manner in which it intends to allocate the incremental revenue requirement to the various customer rate classes, the rationale for the selected approach and a discussion of the merits of alternative allocations considered.

Distributors will also be expected to file a detailed proposal including justifications to recover, through a rate rider, the Board-approved incremental revenue requirement. The proposal should specify whether the rate rider will apply on a fixed or variable basis, or a combination thereof, and the time period for collection. A detailed calculation of the rate rider(s) should be provided for each year of the IR plan term.

Accounting Treatment

Eligible **Z-factor** amounts should be included in Account 1572, "Extraordinary Event Costs", of the Board’s Uniform System of Accounts of the Board’s Uniform System of Accounts contained in the Accounting Procedures Handbook for electricity distributors.

Eligible **Incremental Capital Module** amounts should be recorded in account 1508, Other Regulatory Asset, Sub-account Incremental Capital Expenditures.

Carrying charge amounts shall be calculated using simple interest applied to the monthly opening balances in the account and recorded in a separate sub-account of this account. The rate of interest shall be the rate prescribed by the Board for the respective quarterly period for deferral and variance accounts. These prescribed rates are reviewed and updated each quarter and published on the Board’s web site.

Supplemental Report of the Board on 3rd Generation Incentive Regulation of Ontario's Electricity Distributors
September 17, 2008

Ontario Energy Board

Ontario

EB-2007-0673

Supplemental Report of the Board

on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors

September 17, 2008

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1 Overview

On July 14, 2008, the Board issued its "Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors" (the "July 14, 2008 Report")[1]. That Report sets out the Board's policies and approach to 3rd generation incentive regulation ("3rd Generation IR").

When the July 14, 2008 Report was released, the Board had not yet determined the values for the productivity factor, the stretch factor, and the capital module materiality threshold. These were identified in the July 14, 2008 Report as the three outstanding matters that would benefit from further consultation prior to the Board making a determination on the values. Two Board Members, Mr. Paul Sommerville and Mr. Paul Vlahos, presided over a stakeholder conference held on August 5 – 7, 2008, to provide a forum for further discussion of these issues. At the end of the stakeholder conference, the Board Members indicated that they would report to the Board on the stakeholder conference, following which the Board would make a determination on the outstanding issues.

The participants at the stakeholder conference were:

Participants	Representing
Mr. Maurice Tucci Prof. Adonis Yatchew of the University of Toronto	Electricity Distributors Association ("EDA")
Ms. Susan Frank Ms. Paula Conboy, Ms. Lynne Anderson Ms. Julia Frayer of London Economics International, LLC ("LEI")	Hydro One, Inc. ("Hydro One") and the Coalition of Large Distributors (Enersource Hydro Mississauga Inc., Horizon Utilities Corporation, Hydro Ottawa Limited, Powerstream Inc., Toronto Hydro-Electric System Limited And Veridian Connections Inc.) (the "CLD")

[1] Available on the Board's website at http://www.oeb.gov.on.ca/OEB/_Documents/EB-2007-0673/Report_of_the_Board_3rd_Generation_20080715.pdf.

Participants	Representing
Mr. Peter Thompson	The Canadian Manufacturers & Exporters (“CME”)
Ms. Julie Girvan	The Consumers Council Of Canada (“CCC”)
Mr. David Macintosh	Energy Probe Research Foundation (“Energy Probe”)
Mr. Randy Aiken	London Property Management Association (“LPMA”)
Ms. Judy Kwik	The Power Workers' Union (“PWU”)
Mr. Jay Shepherd	The School Energy Coalition (“SEC”)
Mr. Bill Harper	The Vulnerable Energy Consumer's Coalition (“VECC”)
Ms. Lisa Brickenden Mr. Allan Fogwill Ms. Marika Hare Mr. Bill Cowan Dr. Lawrence Kaufmann of the Pacific Economics Group, LLC (“PEG”)	Board Staff

This Report sets out the Board’s determination of the values for the productivity factor, the stretch factor, and the capital module materiality threshold for use in 3rd Generation IR. This Report also sets out the Board’s determination on the issue of tax changes in relation to the Z-factor.

This Report is organized as follows. Each of the sections in Chapter 2 deals with an outstanding issue (i.e., the value for each of the productivity factor, the stretch factor, and the capital module materiality threshold) and is comprised of three subsections: the first briefly describes the issue, the second summarizes participants’ comments, and the third sets out the Board’s policy and rationale. Chapter 3 addresses the issue of tax changes in relation to the Z-factor. Appendix B to this Report contains an amended version of the filing guidelines that were set out in the Appendix to the July 14, 2008 Report. The amendments to the filing guidelines reflect the Board’s determinations in this Report.

2 Values for Certain IR Plan Parameters

2.1 Productivity Factor

In the July 14, 2008 Report, the Board stated that while it is clear to the Board that participants support an index based approach for the derivation of an industry productivity trend to form the basis for the productivity factor for the incentive regulation ("IR") plan, the Board would be assisted by further consultation on the interpretation of the results in order to determine the appropriate value for the productivity factor.

The question to be addressed by participants at the stakeholder conference was: what is the appropriate value for the total factor productivity ("TFP") trend?

Issues and Options Raised in Consultations

The table in Appendix A summarizes the recommendations and supporting assumptions of Dr. Kaufmann, Prof. Yatchew, Dr. Cronin[2], and Ms. Frayer for the appropriate value for the productivity factor in 3rd Generation IR.

PEG's report entitled "Calibrating Rate Indexing Mechanisms for Third Generation Incentive Regulation in Ontario" (the "PEG IR Report") details the productivity study carried out (the "PEG Study") to arrive at PEG's recommended 0.88 percent value for the productivity factor in 3rd Generation IR. This value is based on U.S. data. Since there is insufficient Ontario data for setting a productivity factor for 3rd Generation IR, PEG used U.S. data after carrying out a comparative analysis to demonstrate that TFP growth for U.S. distributors is a reasonable proxy for contemporaneous Ontario distributor trends. Dr. Kaufmann submitted that he believed this a reasonable measure

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[2] Dr. Frank Cronin, retained by the PWU, did not attend the August stakeholder conference. He made his recommendations in written comments over the course of this consultation.

and that the methodology used to arrive at the recommended productivity factor can be easily applied to Ontario data in the future.

In relation to recent slow productivity growth evident in both the U.S. data and in the available Ontario data, Dr. Kaufmann noted that this has happened before as shown in the 1st generation performance-based regulation ("1st Generation PBR") productivity analysis (the "Cronin and King Study")[3] – slow productivity growth between 1988 and 1993 was followed by rapid productivity growth between 1993 and 1997. Given that experience, Dr. Kaufmann commented that he did not believe that he should assume that the recent slow TFP growth will necessarily continue in the future. As a consequence, PEG did not put any extra weight on the TFP growth of the last four years as did Prof. Yatchew.

The average annual productivity growth over the period 1988-2006 was 0.72 percent. The 0.88 percent value proposed by PEG is restricted to the period 1995-2006, a value that is based on a "start date analysis". Dr. Kaufmann explained that the purpose of PEG's start date analysis is to isolate the long-term trend as much as possible from systemic externalities, such as weather and the economy, so that TFP is not measured in a way that it is distorted by transitory impacts. Therefore, Dr. Kaufmann used statistical analysis to estimate the impact of heating degree days, cooling degree days, and unemployment rate on measured TFP growth. This analysis revealed that 1995 was most similar to 2006, the most recent year in the U.S. data set, and therefore was selected as the "start date" which was least likely to distort measured TFP growth due to transitory weather or economic conditions.

While Prof. Yatchew expressed a preference for the use of Ontario data to set a productivity factor for Ontario distributors, he accepted the PEG Study and the use of U.S. data and provided his advice on how to interpret the results for Ontario distributors.

[3] Cronin, F.J., M. King and E. Colleran. PHB Hagler Bailly Consulting. Productivity and Price Performance for Electric Distributors in Ontario. Prepared for Ontario Energy Board Staff, July 6, 1999. Available on the Board's web site at http://www.oeb.gov.on.ca/documents/cases/RP-1999-0034/ppp1.html

Prof. Yatchew recommended a productivity factor of 0.55 percent which incorporates long-term average productivity growth of 0.72 percent and assigns greater weight to recent (2002-2006) slower productivity growth observed in both U.S. (0.41 percent) and Ontario data (0.01 percent estimated by PEG in the PEG IR Report). Noting that the Board took both recent and long-term patterns in productivity growth into account when it determined the policies and approach to 1st Generation PBR, Prof. Yatchew assigned a ⅔ weight to the long-term average and a ⅓ weight to the recent average, resulting in a point forecast figure of 0.55 percent as summarized in Table 1.

Table 1: Estimation of the 0.55%

Assigning a ⅔ weight to the long-term average and a ⅓ weight to the recent average:
0.49% = ⅔ 0.72% + ⅓ 0.01%
0.62% = ⅔ 0.72% + ⅓ 0.41%
0.55% ~ mid point between 0.49% and 0.62%

Prof. Yatchew commented that Dr. Kaufmann's productivity factor of 0.88 percent inappropriately restricts data to the 1995-2006 period and does not assign any additional weight to the more recent data. In his review of the PEG Study, Prof. Yatchew found no statistical evidence of systematic acceleration or deceleration in productivity growth throughout the sample period. He expressed concern with Dr. Kaufmann's "start-date analysis" in that he found no evidence of this approach in the mathematical statistics literature or in econometrics literature that would justify this kind of approach in this kind of setting. Prof. Yatchew suggested that if the Board wishes to move forward to create a predictable and evolving regulatory environment, the Board should not embed an algorithm for which he was unable to find support in academic literature. He proposed that the Board should include the entire 1988-2006 period to set the productivity factor for two reasons. First, Prof. Yatchew submitted that the "start-date analysis" fails because it searches for a single year that is most similar to the most recent year, rather than for a period that is likely to be representative of the future. Second, he noted that including the entire 1988-2006 period is based on the fundamental idea in statistics that larger samples deliver more precise estimates.

As noted in the July 14, 2008 Report, Dr. Cronin, in his written comments, recommended a productivity factor "menu" approach. Under that approach, distributors would be allowed to select from a menu of productivity factors, each with an associated allowed return on equity ("ROE"). Research during 1st Generation PBR found a ten-year mean growth rate of slightly more than 0.8 for TFP. Research subsequent to 1st Generation PBR found a mean ten-year growth rate of about 1.6 percent for TFP for most efficient firms[4]. On this basis, Dr. Cronin recommended that the "baseline" option in a menu should be a productivity factor of 0.8 percent with an associated allowed ROE of 8.5 percent. The proposed menu also included four other options, where increments of 0.2 percent in the productivity factor are associated with 100 basis point increments in the allowed ROE. The maximum productivity factor of 1.6 percent was therefore associated with a 12.5 percent allowed ROE.

Ms. Frayer submitted that the productivity factor should be measured using Ontario data for the industry and that results from other jurisdictions can be useful as checks but cannot substitute for Ontario-specific business circumstances. Specifically, Ms. Frayer commented that Ontario has many smaller distributors (the U.S. has typically much larger franchise areas in terms of geographical span and customers) and that Ontario distributors:

- with few exceptions, operate only electricity distribution businesses;

- face unique weather, have diverse customer bases, and have a distinct legacy of system configuration and network expansion because of government and municipal ownership which impacts input/output relationships and potential for productivity growth;

- have been under rate freezes, de facto price caps since the mid 1990s, while also processing corporatization changes and market restructuring; and

[4] Cronin, F. and S. Motluk, "Leaders and Laggards: Examining Regulatory Applications of the Mamquist Productivity Index to Establish Secular Growth in Productivity." (forthcoming)

- will, in some cases, soon be in a dramatic capital expenditure ("CAPEX") phase because of an aging asset base resulting from provincial mandates to electrify in the 1960s and 1970s.

Therefore, Ms. Frayer recommended using a 20-year average TFP growth measure of 0.58 based on the results of three different productivity studies: the Cronin and King Study (1988-1997), PEG's projections for the "missing years" of 1998-2002 developed to facilitate PEG's U.S.–Ontario industry trend comparisons[5] and LEI's independent analysis of data filed under the Board's Electricity Reporting and Record Keeping Requirements ("RRR") (2003-2007). The three studies employ the index method to derive TFP growth; however, they include different measures for inputs quantities or values (e.g., labour, materials, and capital) and output quantities or values (e.g., throughput, customer numbers, and peak demand). In particular, the Cronin and King Study and the PEG Study used the monetary approach to account for capital quantities. In its five-year study, LEI chose to measure capital input quantity based on the physical length of distribution lines because of physical depreciation profile effects. That is, Ms. Frayer proposed that the carrying capacity of distribution lines does not decline consistent with accounting depreciation methods. Ms. Frayer submitted that economic theory, empirical evidence, industry experience and recent regulatory precedent all support the recognition of this approach when calculating the annual capital input quantity of electricity distribution assets and that accounting depreciation adjustments under the monetary approach bias the quantity of capital input. Ms. Frayer observed that over the most recent years, on average, TFP growth for the industry has been negative and submitted that this negative trend needs to be acknowledged and included in the analysis. LEI tested various weighting schemes for output which produced similar overall trends showing negative TFP growth. The value of 0.58 percent is an average

[5] PEG developed four scenarios for TFP growth during the "missing years" between 1998 and 2002 in Ontario. PEG emphasized that they do not put forward any of these scenarios as accurate measures of TFP growth during that time. Rather, PEG is trying to bind the range of possible TFP growth rates for the Ontario industry over the entire 1988-2006 period, which will facilitate their comparisons with the U.S. industry over the same period. See PEG IR Report (p. 55).

of the percent change in the derived TFP index for each year over the 1988-2007 period and recognizes and incorporates recent negative trends in TFP growth.

Ms. Frayer explained that LEI did not include weather normalization because they wanted to present actual results subject to the actual operating conditions faced by distributors (i.e., they do not operate under weather-normalized conditions). Ms. Frayer submitted that, as a result, total factor productivity would be measured on the basis of actual figures, since that productivity will then form the productivity target which will affect actual revenues regardless of the weather in the future.

CME, in response to Prof. Yatchew's view that larger samples deliver more precise estimates, asked the consultants their views on what is the minimum period for statistical significance. In response, Ms. Frayer indicated her view to be seven to ten years, Prof. Yatchew suggested eight to ten years, and Dr. Kaufmann indicated that his view of the minimum period would be nine years.

In relation to the LEI study, most participants, as well as Dr. Cronin and Dr. Kaufmann, disagreed with the use of physical counts of capital in the calculation of TFP. Both of them recommended the customary use of monetary values. Dr. Kaufmann noted that when a utility sets its rates to recover depreciation and carrying costs associated with these capital goods, it does so with reference to the aggregated monetary values of these disparate assets net of their depreciation. He submitted that LEI's TFP study ignores this monetary valuation of assets in favour of a physical method for estimating capital stock. Since physical asset measures are not used to set rates at the outset of a plan, Dr. Kaufmann expressed concern over LEI's proposal to use a productivity factor to adjust distribution rates that, over time, bears no relationship to how those rates were originally set. Dr. Kaufmann also noted that the LEI TFP model assumes that there is no physical decay of distribution assets over time. He stated that there is no theoretical or empirical support for this assumption and cautioned that this is not an academic point but a practical one, because depreciation is a reality. CME submitted that the use of physical counts of capital is incompatible with the monetary approach that was used to derive the TFP trends for the periods 1988-1997 and 1998-2002 on which LEI relies, and the effect appears to materially distort the LEI trend downwards.

Most participants representing ratepayer groups supported Dr. Kaufmann’s recommended 0.88 percent value for the TFP trend to be used as the base productivity factor for all electricity distributors in 3rd Generation IR. LPMA and Energy Probe commented that while Dr. Kaufmann's recommendation of 0.88 percent is “in the right ballpark”, it is at the lower end of the range than should be considered for three reasons. First, Dr. Kaufmann has indicated that compared to values set in other jurisdictions in recent plans (generally one percent or higher), his 0.88 recommendation is on the low side. Second, the Board has endorsed the concept of a capital module. The inclusion of this module in IR should be reflected by a higher productivity factor to account for this deviation from the norm and for the relief that it may provide to distributors. Third, the three utility multi-factor productivity indices available from Statistics Canada show average growth rates of 0.86 percent, 1.07 percent and 1.08 percent over the period for which the data is available. Mr. Aiken noted that the Statistics Canada data on productivity numbers for utilities goes as far back as 1961. The average of these three rates is 1.00 percent. CME suggested the value be no less than 0.80 percent which is the mid-point between the average annual productivity growth in the U.S. electricity distributor data of 0.72 percent and the PEG-recommended 0.88 percent based on its “start date” analysis.

VECC expressed concern with the LEI study in that there was no weather normalization undertaken for the study period. VECC observed that weather normalization may not be critical when dealing with very long periods of time as the impacts will be somewhat smoothed out. However, VECC submitted that weather normalization is critical when dealing with a short period of time. During the timeframe in question, 2002-2007, VECC noted the extreme weather conditions in 2002 and how that influenced not only the operations of distributors but subsequent government policy decisions in Ontario. Further, VECC observed that while the term of the 3rd Generation IR plan is three years, the plan will actually be in effect over three tranches of distributors over a period of five years. Therefore, VECC disagreed that recent downward trends in productivity should be presumed to persist that long. VECC concluded that a value in the order of 0.72 to 0.88 percent may be the appropriate productivity factor. According to VECC, if the Board is concerned about the start/end date analysis, the Board could gravitate more towards the 0.72 value.

Hydro One and the CLD recommended that the value of the productivity factor be set within the range of 0.55 and 0.58 percent. The compound effect of declining load growth due to conditions such as a slowing economy and conservation and demand management activities, and rising costs due to conditions such as an aging work force, escalating fuel costs, changing accounting standards, and new environmental regulation requirements will make it a challenge to even achieve productivity within that range over the next three years.

Board Policy and Rationale

In the July 14, 2008 Report, the Board determined that X-factors assigned to individual distributors will consist of an empirically derived industry productivity trend (productivity factor) and stretch factor. The Board has not adopted a “menu” approach.

The Board notes that there was general consensus amongst the consultants on the following points:

- that estimating industry TFP trends is a common element in IR- based rate setting regimes;

- that the development of these trends in any given regulatory regime is highly dependent on the quantity and quality of data reflecting the experience of the utilities governed by the IR plan; and

- that the development of an Ontario-specific TFP trend for the 3rd Generation IR mechanism is hindered by a lack of data covering a sufficient period of time.

Accordingly, the proposals put forward by each of the consultants represented a compromise that was to some degree caused by this deficiency in data.

As noted above, PEG proposed a TFP value of 0.88 percent. This number was developed using U.S. utility data due to the absence of sufficient Ontario distributor data. While no detailed critique of the U.S. data set was undertaken by any of the other consultants, even PEG regretted having to resort to the use of non-Ontario data. It is also clear that some firms in the U.S. data set were vertically-integrated utilities and that their productivity profiles may be somewhat different than those of stand-alone distribution companies. While PEG's analysis controlled for this, it is noted that the results may still be somewhat skewed. In addition, PEG used a "start date analysis", described above, which was the target of some criticism by other consultants.

Ms. Frayer considered the use of U.S. data to be a significant shortcoming of the PEG proposal. In her view, the Ontario context is distinct and the use of U.S. data is unsound. Faced with the same data deficiency as the other consultants, she used a series of previous studies in combination with a unique approach to the consideration of capital as a component of the TFP trend calculation. She also argued for greater weight to be given to the more recent TFP trend to reflect the deceleration in growth in recent years in Ontario. In her view, the TFP value should be set at 0.58 percent.

Prof. Yatchew reluctantly accepted the use of U.S. data, but objected to the "start date analysis", which in his view is inappropriate and unprecedented. He also suggested, as did Ms. Frayer, that increased weight ought to be given to the most recent TFP trend. He proposed a TFP value of 0.55 percent.

In the Board's view, the data deficiencies noted by the consultants do not operate as an insurmountable obstacle to the development of an appropriate TFP value for 3rd

Generation IR. The Board accepts the use of U.S. data for the purposes of the derivation of the TFP trend for 3rd Generation IR. Use of this data set was supported by PEG and Prof. Yatchew. Ms. Frayer sought to circumvent the problem through a patchwork of studies that, in the Board's view, are not adequately demonstrated to be based on a series of consistent principles. Of greatest concern with Ms. Frayer's approach is the measurement of capital, which is inconsistent with the prior Ontario TFP studies and does not appear to have been adopted in any jurisdiction other than New Zealand. While the Board recognizes Ms. Frayer's efforts to construct an Ontario-specific TFP trend, the Board does not believe that the methodology advocated by Ms. Frayer is appropriate. The Board is optimistic that the current data deficiencies will recede as the Board accumulates data from the sector over the next several years. Within the next five years the data issue will have been resolved, and the development of an Ontario-specific TFP trend can proceed on a more solid footing.

The Board is not convinced that the "start date analysis" used by PEG, which limits the data sample to the period 1995-2006, is necessary or warranted. The Board agrees with Prof. Yatchew's statement that greater confidence can be derived from using the full data set, in this case representing U.S. data from 1988 to 2006.

Similarly, the Board is not persuaded that increased weight ought to be given to the most recent TFP trend. The merit of using the full data set is that the resultant TFP trend can be reasonably expected to reflect the ebbs and flows experienced over a relatively long period of time. To weight the most recent trend would undermine one of the virtues of using the full data set.

Accordingly, the Board has determined that the appropriate value for the TFP trend for 3rd Generation IR is 0.72 percent, the average annual productivity growth over the period 1988-2006 in the full set of U.S. electricity distributor data used by PEG. The Board is not convinced that the "start date analysis" is sufficiently well developed to justify limiting the sample. The Board believes that this value reflects a reasonable synthesis of the various points of view advanced in the course of the stakeholder consultations and of the Board's views on the relative merits of the approaches put forward by the various participants.

As indicated in the Board's July 14, 2008 Report, this value will be fixed for the term of the plan.

2.2 Stretch Factors

In the July 14, 2008 Report, the Board determined that it will use the results of two benchmarking evaluations to divide the Ontario industry into three efficiency "cohorts". The two evaluations will be compared and those distributors that rank superior in both will be assigned to Group I. Those distributors that rank inferior in both will be assigned to Group III. All other distributors, including those that rank superior or inferior in only one of the evaluations, will be included in the broad middle cohort, Group II. At the time of the release of the July 14, 2008 Report, the Board had not yet determined the stretch factor value to be assigned to each cohort.

The question to be addressed by participants at the stakeholder conference was: what are appropriate stretch factor values for each of the three groups?

Issues and Options Raised in Consultations

Table 2 summarizes participants' recommendations for the appropriate stretch factor values for each of the three groups in 3rd Generation IR.

Table 2: Summary of Stretch Factor Recommendations

	Efficiency Cohort/Group		
	I	II	III
	Statistically superior and in top quartile on OM&A unit cost comparison	*In middle two quartiles on OM&A unit cost comparison*	*Statistically inferior and in bottom quartile on OM&A unit cost comparison*
VECC	0.25%	0.50%	0.75%
CCC (two recommendations)	0.25%	0.50%	0.75%
	0.50%	0.50%	0.50%
LPMA and Energy Probe (two recommendations)	0.25%	0.50%	0.75%
	0.35%	0.50%	0.65%
SEC	0.00%	0.50%	1.00%
Ms. Frayer, LEI, on behalf of Hydro One and the CLD	0.00%	0.075%	0.15%
Prof. Yatchew, University of Toronto, on behalf of the EDA	0.00%	0.10%	0.20%
Dr. Kaufmann, PEG, Board staff's consultant	0.00%	0.25%	0.50%

As noted previously, Dr. Cronin recommended a productivity factor "menu" approach in his written comments. Dr. Cronin submitted that the menu would incorporate distributor diversity into the IR plan.

Dr. Kaufmann noted that determining the values of the incremental productivity gains that firms are expected to achieve under IR is a more forward-looking exercise than estimating a productivity factor which is typically derived using historical TFP trends. In practice, he advised, most stretch factor values approved in North America have been based on judgment and have varied from zero to one percent. For 3rd Generation IR, he submitted that relatively modest stretch factors may be more appropriate with the Board's early benchmarking application until the Board better understands distributors' comparative cost performance and potential for incremental productivity gains. Dr. Kaufmann noted that his recommendations acknowledge that distributors in Group I have been demonstrably superior performers and have limited potential to achieve incremental gains in excess of his recommended productivity factor. Further, he submitted, his recommendations are supported by benchmarking studies which find evidence of significant productivity differences, and thus potential for incremental productivity gains, among distributors in Groups II and III. The specific values that Dr. Kaufmann recommended for Groups II and III are reflective of Ontario precedents to date. Most distributors will be in Group II and have a stretch factor of 0.25 percent, which is equal to the value approved for all distributors in 1st Generation PBR, and the 0.5 percent value recommended for Group III is equal to the highest stretch factor approved to date in Ontario (in the incentive regulation plan approved for Union Gas Limited in proceeding RP-1999-0017).

Prof. Yatchew stated that Ontario distributors have been under a form of price-cap regulation for a period of time and have been engaged in a form of yardstick competition[6] for many years. These two factors, he argued, weaken the case for stretch factors in an Ontario electricity distributor IR plan. Prof. Yatchew also reiterated his concerns about the potential for "misclassification" of distributors to cohorts using the OM&A benchmarking studies and concern that the threat of misclassification may focus distributors on reducing OM&A costs rather than total costs, resulting in inefficient resource allocation (e.g., over-capitalization by utilities seeking to reduce OM&A costs; under-spending on OM&A; and sub-optimal decisions with respect to own vs. lease alternatives). He identified four sources of potential misclassification: the use of OM&A rather than total cost data; mismeasurement or omission of his recommended variables; statistical error which he measured at 20 percent; and the use of U.S. rather than Ontario data. Consequently, given that the Board has determined that non-negative stretch factors will be implemented, he recommended that the stretch factors be materially lower than those recommended by Dr. Kaufmann. He noted that his recommended stretch factors of 0.0 percent, 0.1 percent, and 0.2 percent for the three groups would result in X-factors of 0.55 percent, 0.65 percent, and 0.75 percent, and noted that the 0.65 percent value is substantially higher than recently observed productivity growth rates in the U.S. and in Ontario.

[6] Prof. Yatchew described this *informal yardstick competition* as an industry-driven process during the many years that there were many distributors in this province. During that time, there was a systematic process for comparing performance amongst distributors. As distributors found better ways to do things, that information would be shared with others, because there was a relatively open public sector system for doing so.

Ms. Frayer also recommended lower stretch factor values than did Dr. Kaufmann for similar reasons to those put forward by Prof. Yatchew. She also reiterated her view that average performers should receive a zero stretch factor to represent their relatively neutral position to the projected TFP growth for the industry as a whole, and superior performers should receive a negative stretch factor to reflect their superior performance and their reduced ability to improve on that performance. Ms. Frayer took the approach that the stretch factor ought to be set in such a manner so that the maximum possible X factor (i.e., productivity factor plus stretch factor) component of the IR formula would be equal to the highest estimate for long term TFP growth (i.e., 0.73 percent) of four 20-year TFP analysis scenarios. She recommended basing the stretch factor values on implied lower and upper bounds from four 20-year TFP analysis scenarios comprised of the Cronin and King Study, the PEG Study (2-factor and 3-factor output) and the LEI study (2-factor and 3-factor output). The resultant “upper” bound, “median” and “lower” bound values (0.73 percent, 0.58 percent and 0.42 percent, respectively) form the basis for a recommended 0.15 percent maximum stretch factor. Given that the Board has determined that non-negative stretch factors will be implemented and also noting that small changes in the overall X-factor can create unreasonable financial burdens on distributors, Ms. Frayer recommended stretch factors of 0.0 percent, 0.075 percent and 0.15 percent on top of her recommended industry-wide productivity factor of 0.58 percent.

SEC observed that, in 3rd Generation IR, the stretch factor is of particular importance since there is no earnings sharing as part of the plan and rebasing to date has not demonstrated the theory that productivity gains achieved by distributors flow through to ratepayers forever thereafter. Acknowledging regulatory precedent and judgment, SEC submitted that “the right number” has to be meaningful in that it has to matter to the distributors. SEC noted that as part of the Board’s determination for the Z-factor threshold for 3rd Generation IR, the Board determined that 0.5 percent of distribution revenue requirement is material. SEC reasoned that if half of one percent is what matters enough to qualify a distributor for an adjustment to its underlying revenue requirement, then half of one percent is also what matters enough to influence a distributor's behaviour. In response to a suggestion that it might be possible to use the same stretch factor value for all three cohorts, SEC disagreed. SEC expressed concern that the Board would identify some distributors as being more efficient than others but that there would not be any consequence to it. Therefore, he recommended that the difference between the midpoint and either the bottom point or the top point should be 0.5 percent. In summary, SEC recommended stretch factors of 0.0 percent, 0.5 percent and 1.0 percent on top of Dr. Kaufmann's recommended industry-wide productivity factor of 0.88 percent.

While Dr. Kaufmann agreed with Prof. Yatchew that the theoretical rationale for stretch factors is that IR creates stronger incentives compared with cost-of-service regulation, he submitted that theory never says that stretch factors should only be implemented one time (i.e., in the first IR plan) and then be removed. Rather, he noted specific precedents in the U.S., Germany, and the U.K., as well as more general evidence from regulated industries to the effect that incremental productivity gains are sustained for more than a decade after regulatory reform (e.g., U.S. railroads, U.K. energy distribution).

All participants acknowledged that the stretch factor is based on judgment and that factors that could influence the Board's judgment include the term of the plan, the absence of an earnings sharing mechanism, and the inclusion of an incremental capital module. Participants also generally agreed that, in the long-term, when total cost benchmarking and the requisite data are available, the source of misclassification may be reduced to statistical error (which will always exist). Prof. Yatchew observed that part of the value of this process is that distributors that believe they are being treated inequitably will come forth with that information and hopefully improve the nature of the entire information set.

LPMA, Energy Probe, CCC and VECC recommended that the stretch factors be set at 0.25 percent, 0.50 percent, and 0.75 percent. LPMA and Energy Probe submitted that without an earnings sharing mechanism, the values for the stretch factors should at least be set relative to that which is evident in comparable IR plans. The recommended value for Group II is based on what Dr. Kaufmann indicated as the average stretch factor set in North America, and on what has been historically set in a Union Gas plan here in Ontario. With regard to Group I, LPMA and Energy Probe argued that the value should be greater than zero because there is no evidence to suggest that productive distributors will not or cannot continue to achieve additional gains. Their opportunity may be less, but LPMA and Energy Probe maintained that it is still greater than zero.

VECC commented that the stretch factor is in effect addressing three issues. First, the productivity factor reflects what a normal cost-of-service type application may result in, including the type of benefit a consumer might expect to see in terms of the resulting rates under a cost-of-service regime. If one accepts that there is greater opportunity for productivity improvements by distributors under IR, then according to VECC it seems reasonable to expect something in addition to that – the stretch factor. Second, there are a number of safety valves in the 3rd Generation IR design for distributors. Depending on a distributor's circumstance, the distributor may be eligible to apply for Z-factors, off-ramps, or revenue to support incremental capital. A distributor may also apply for a full cost-of-service review. With no earnings sharing mechanism, the stretch factor is in VECC's view also a safety valve for consumers. Third, the stretch factor is meant to recognize the fact that there are differences in terms of where distributors stand right now in terms of their level of efficiency, as reflected in the Board's decision to have three groupings. VECC concluded that the stretch factor for Group I should therefore be greater than zero. VECC recommended stretch factor values of 0.25 percent, 0.5 percent and 0.75 percent for the three groups.

With respect to Prof. Yatchew's concerns that 20 percent of the distributors, on average, will be misclassified as either being statistically superior or statistically inferior, CME observed that this would mean two out of the eleven distributors assigned to Group I may not belong there, and about two out of the eleven distributors assigned to Group III may not belong there. Consequently, CME proposed that the response to the misclassification concern should not be to reduce the stretch factor on average, but rather that it may be more appropriate to narrow the differences between the average stretch factor and the stretch factors for Group I and Group III. While CME did not recommend specific values, it recommended that the Group II stretch factor be set in the range of 0.25-0.50 percent. LPMA and Energy Probe, building on this idea, recommended that if the Board believes that some sort of mitigation against misclassification is required, then the stretch factor values could be set at 0.35 percent, 0.50 percent, and 0.65 percent for the three groups. CCC submitted that, if the Board were to accept the arguments about misclassification, CCC would support a stretch factor of 0.5 percent for all three cohorts.

Hydro One and the CLD noted that all participants seem to agree that benchmarking is in its infancy, that it needs to improve and that it will improve. These distributors acknowledged that there will likely be some misclassification, but that improvements will be made over time and therefore, they submitted, they support the Board's grouping approach. As to the values for the stretch factors, Hydro One and the CLD commented that, from their perspective, what is important is the combination of what is expected of them in terms of productivity plus a stretch factor because that is the number that needs to be achieved. Therefore, if the Board sets one high, perhaps it should set the other one low or vice versa – it is the combination that distributors are going to have to somehow manage to achieve. In summary, Hydro One and the CLD expressed a preference for the values 0.0 percent, 0.075 percent, and 0.15 percent for the three groups.

Board Policy and Rationale

It is important to note that stretch factors are consumer benefits. They are somewhat analogous to earnings sharing mechanisms, although stretch factors take effect immediately with the application of the formula and are not dependent on the realization of any productivity gains or excess earnings, as would be the case with an earnings sharing mechanism. Stretch factors are an integral part of the IR formula, and are not dependent on future performance by the utility.

In the July 14, 2008 Report, the Board determined that stretch factors will be a feature of the IR mechanism, and that benchmarking will provide the architecture for their assignment to distributors. These determinations were not intended to be revisited during the August stakeholder conference. The Board acknowledges the concerns expressed regarding the current state of benchmarking in Ontario, but is not convinced that it needs to reconsider the benchmarking architecture for purposes of 3rd Generation IR.

The Board notes that all of the participants in the consultation agreed that the setting of stretch factors is a matter that calls for the exercise of judgment. As such, there are no hard and fast principles to guide the Board's determination of an appropriate value. The Board also notes that each of the participants urged the Board to take a conservative approach with respect to the stretch factor values in light of the fact that the Board's experience with benchmarking is in its early stages.

The Board is not convinced that the potential for misclassification raised by Dr. Yatchew is such that the Board needs to reduce the stretch factors so that they are of little or no materiality. As described in the July 14, 2008 Report, the three groupings have been developed using two distinct benchmarking evaluations. The two evaluations will be compared and those distributors that rank superior in both will be assigned to Group I. Those distributors that rank inferior in both will be assigned to Group III. All other distributors, including those that rank superior or inferior in only one of the evaluations, will be included in the broad middle cohort, Group II. The Board recognizes that the risk of misclassification cannot be ruled out. The Board intends to undertake further work on the model and will consult with stakeholders to identify whether it can improve the grouping approach and further reduce the potential for misclassification in the two OM&A benchmarking evaluations. It is also expected that the Board's knowledge of and facility with benchmarking will improve over the course of the 3rd Generation IR, and that any anomalies will be addressed in due course.

The Board also believes that it is important that the stretch factors be sufficient to influence distributor behaviour over the course of the plan. While the Board accepts that this is not the time to adopt large stretch factors, it does believe that they must be of such magnitude that they are likely to motivate distributors to change or maintain their status, as the case might be. The proposals put forward by Ms. Frayer and Prof. Yatchew would not, in the Board's view, be meaningful in that regard. The Board also believes that Ms. Frayer's approach would conflate the TFP and the stretch factor, effectively eliminating the consumer benefit element normally associated with the stretch factor.

As noted above, some participants argued that the best performers, or even average performers (i.e., those falling within Group I, or Group II), ought to enjoy a zero stretch factor. In fact, in earlier comments made within this consultation some participants argued for negative stretch factors for high performing distributors. At this time, the Board is not prepared to accept the premise there are no prospects for incremental productivity gains above the expected industry trend that should be shared with ratepayers – which a stretch factor of zero or less would connote. While these options may commend themselves in future IR plans, the Board does not think it appropriate at this time, and has adopted a modest but still meaningful stretch factor for Group I, and a higher stretch factor for Group II.

With respect to Group III (the poorest performers), the Board believes that the stretch factor value should not be so demanding as to be considered punitive. In the Board's view, the stretch factor approach ought to serve as an incentive for incremental productivity improvement and not as a punitive measure.

Accordingly, the Board has determined that the appropriate stretch factor values for each of the three groups are as follows:

Table 3: Stretch Factor Values

Group	Benchmarking Evaluations	Stretch Factor Value
I	Statistically superior and in top quartile on OM&A unit cost comparison	**0.2%**
II	In middle two quartiles on OM&A unit cost comparison	**0.4%**
III	Statistically inferior and in bottom quartile on OM&A unit cost comparison	**0.6%**

These values will be in effect for the term of the plan. As indicated in the July 14, 2008 Report, each year the cohorts for the entire sector will be re-evaluated. This means that the stretch factor for a given distributor may change during the term of the IR plan if the distributor moves from one group to another.

The Board believes that the above stretch factor values reflect a reasonable synthesis of the various points of view advanced in the course of the stakeholder consultations and of the Board's views on the relative merits of the approaches put forward by the various participants.

2.3 Incremental Capital Module Materiality Threshold

In the July 14, 2008 Report, the Board determined that there will be an incremental capital module in 3rd Generation IR. Further, the Board determined that the eligibility of a distributor to apply for rate relief through the module will be subject to a materiality threshold. However, the Board stated that it would be assisted by further consultation on the appropriate materiality threshold.

The question to be addressed by participants at the stakeholder conference was: what is an appropriate CAPEX to depreciation threshold value to determine materiality?

Issues and Options Raised in Consultations

Board staff provided analysis that indicated that CAPEX to depreciation threshold values in the range of 170-190 percent may be appropriate. These threshold values are comprised of three parts:

- a 100 percent base depreciation value;
- an additional 20-40 percent for the annual 3rd Generation IR price cap index ("PCI") adjustment value (20 percent if PCI adjustment is one percent; 40 percent if PCI adjustment is two percent); and
- an additional 50 percent to adjust depreciation from historical to replacement dollars.

Board staff's 50 percent estimate for inflating depreciation expense to replacement dollars was derived as follows. An overall effect of inflation adjustment was estimated as 49.1 percent based on the published Ontario total values for depreciation expense, remaining book value of in-service plant and Statistics Canada inflation statistics. While an Ontario average was used to illustrate a single value as a threshold component for all distributors (~50 percent), staff noted that a table of depreciation escalators could be prepared for use with a variety of different average ages to reflect individual distributor age of plant.

Staff's threshold calculations did not attempt to adjust for customer or load growth. Staff noted that growth provides incremental funding for new capital and that this would be evident in a distributor's application to the Board and reviewed on a case-by-case basis.

While PEG did not make specific recommendations on the value of the threshold, Dr. Kaufmann emphasized that an implicit adjustment for CAPEX exists in the PCI because a historical level of CAPEX is built into the productivity factor. If a distributor has historically invested in more CAPEX, it will consequently have lower TFP growth, all else being equal, and that would translate into more rapid price escalation. Acknowledging that special CAPEX adjustments could be warranted if, for whatever reason, a distributor's future CAPEX differs in a significant way from what is reflected in historical industry-based trends, Dr. Kaufmann cautioned that the Board be careful to ensure that any such CAPEX adjustment does not allow double counting.

Ms. Frayer also acknowledged that some portion of rate base growth is already remunerated through the PCI; however, she submitted that the need for an incremental capital module arises because rate base is growing faster than the rates under the price cap regime, even if annual CAPEX stays at the same level over an IR plan term. Ms. Frayer explained that the annual PCI adjustment may not be sufficient for all distributors, depending on the depreciation profile and the capital additions profile for a particular distributor. Ms. Frayer commented that growth in rate base that is “unfunded” results in potential loss of capital carrying costs and potential for deteriorating ROE, despite distributors’ best efforts for cost cuts and/or delay in CAPEX. Ms. Frayer provided an illustrative analysis of incremental rate base and the need for rates – a rate adder of some sort or revenue adder – to cover that unfunded amount of incremental rate base. Based on the experiences of Hydro One and the CLD, expectations on inflation and LEI’s recommended productivity and stretch factors, Ms. Frayer proposed that a 2 percent growth in rate base is sufficiently material to have a significant influence on distributor operations. Given this, Ms. Frayer provided the following analysis. In 2007 the IR PCI adjustment was 0.9 percent. Assuming that 60 percent of a distributor’s revenue requirement is related to capital, she also assumed that 0.54 percent of the PCI adjustment (i.e., 60 percent of 0.9 percent) is available for capital-related costs, regardless of rate base growth. In contrast, on a rate rebasing basis, a 2 percent increase in rate base would result in about a 1.2 percent (i.e., 60 percent of 2 percent) increase in revenue requirement. Ms. Frayer noted that, in this example, the 2007 price cap would have fallen short on funding by 0.68 percent (i.e., 1.2 percent less 0.54 percent).

Ms. Frayer acknowledged the linkage between the CAPEX to depreciation ratio and rate base growth, and provided analysis to illustrate that linkage. Based on her analysis of RRR reported data for 2007, Ms. Frayer noted that there is a strong correlation between the two percent growth in asset base that she identified as material and substantial and a 125 percent ratio of CAPEX to depreciation expense. Therefore, Ms. Frayer recommended a 125 percent CAPEX to depreciation threshold.

CME and Board staff clarified with Ms. Frayer that her proposed value of 125 percent is derived based on estimated asset base growth, not load growth. Ms. Frayer commented that funding from the PCI, load growth, or other sources would be dealt with in the distributor's application to the Board rather that factored into the threshold value.

Mr. Shepherd, representing SEC, also commented that an implicit adjustment for CAPEX exists in the PCI and reflected this in his proposed approach to deriving distributor-specific values for the materiality threshold. This distributor-specific proposal is in contrast to the proposals offered by Board staff and Ms. Frayer, both of which result in one value for the threshold.

Mr. Shepherd recommended a threshold of 200 percent plus or minus 50 percent of the distributor's average three-year growth percentage, based on the following formula:

$$\textit{CAPEX potential under IR} = \frac{P * R * (d + i + (g * 1.5))}{(d + c)}$$

Where:

- P = percent of revenue requirement that is capital driven (i.e., revenue requirement less OM&A);
- R = revenue requirement of prior year;
- d = depreciation expense as a percent of rate base (i.e., an average depreciation rate);
- i = inflation factor in IR;
- g = organic growth in revenue (i.e., change in load or customer numbers); and
- c = interest + ROE + payments in lieu of taxes (PILs) as a percent of rate base.

(Implicit in the above formula is the annual reduction of cost of existing capital – the annual reduction in rate base reduces the cost of capital associated with old assets and provides additional funds to finance capital.)

Using RRR data, Mr. Shepherd adopted the following assumptions: P = 50% (2007 actual is 48.9%); d = 4% (2007 actual is 6.57%); and c = 8.7% (6% interest on 60%, 8.5% ROE on 40%, 33% combined income tax rate). For illustrative purposes, he adopted the Bank of Canada target rate of 2% for the value of inflation (i), and assumed R=1. Using these assumptions, Mr. Shepherd estimated that IR provides a distributor a CAPEX amount of approximately 25 percent of annual revenue requirement (i.e., g=0%) plus an additional 6 percent for each one percent of organic growth (i.e., g=1%). Translating this into CAPEX to depreciation expense terms, Mr. Shepherd estimated this to amount to approximately 148 percent of depreciation expense plus 36 percent for each one percent of organic growth. Mr. Shepherd provided further analysis to test this 148 percent threshold value against the RRR reported CAPEX in 2007 of 71 distributors. He indicated that 34 percent of those distributors reported CAPEX over the 148 percent of depreciation level, plus or minus growth, and that 66 percent reported CAPEX under that level. He further indicated that if the threshold were raised to 200 percent of depreciation, 14 percent of the distributors' reported CAPEX exceeded 200 percent of depreciation and 21 percent of the distributors' reported CAPEX was 100 percent below depreciation.

Mr. Shepherd submitted that qualifying for the capital module should be an" exception", not a "standard". This view was echoed by other participants. Mr. Shepherd noted that, regardless of the threshold, some distributors may under-spend during IR and that he is much more concerned with this than with the materiality threshold.

Mr. Aiken, on behalf of LPMA and Energy Probe for the purposes of this part of the consultation, proposed a formulaic approach to calculate an individual threshold for each distributor. The formula incorporates both the impact of the price cap and organic growth:

$$\frac{CAPEX}{d} = 1 + (\frac{RB}{d}) * (g + PCI * (1 + g)) \qquad (1)$$

Where:

RB = rate base included in base rates;

d = depreciation expense;

g = distribution revenue change based on load growth; and

PCI = price cap index (inflation less productivity factor less stretch factor).

(Mr. Aiken noted that the values for RB, d, and g, would be taken from the Board-approved base year rate decisions.)

Mr. Aiken arrived at this formula by first establishing a means of estimating the level of CAPEX that can be financed by increases in revenues due to the price cap formula and by load growth as follows:

$$CAPEX = d + RB * (g + PCI * (1 + g)) \qquad (2)$$

The premise of the above is that the approved base year revenue requirement covers OM&A costs and rate base costs (which include depreciation, interest on debt, return on equity and the associated taxes). Mr. Aiken noted that, similar to the other proposals, his proposal recognizes that the revenue generated under a price cap plan automatically generates more revenue for capital investment. Further, the revenue generated under a price cap plan is equal to the approved revenue requirement from the last rebasing year adjusted for the price cap index, as well as load growth.

Mr. Aiken provided various scenarios to illustrate how his proposed formula would reflect distributor diversity. In brief, distributors with relatively new asset stock (suggested by low depreciation relative to rate base) and therefore likely operating earlier in the asset replacement cycle, and distributors in higher growth areas (evidenced by the reported growth rate) and therefore earning faster growing revenue will both have higher CAPEX to depreciation ratios for purposes of this threshold test. Conversely, distributors in low growth areas or with aging assets will have lower CAPEX to depreciation ratios for purposes of the threshold test.

One area where Mr. Shepherd was critical of Mr. Aiken's model is that, in deriving a CAPEX to depreciation threshold, the model does not contain a capital efficiency factor. This could be rectified, Mr. Shepherd noted, by using the gross inflation factor, not netted for the X factor.

In response to staff's proposal and Ms. Frayer's proposal, Mr. Aiken submitted that a one-threshold-fits all approach is not appropriate for the incremental capital module due to the differing demands on distributors across the Province. Most other participants also supported a formulaic approach; however, Mr. Shepherd acknowledged that it may be more efficient for the Board to have a single threshold as opposed to a separately calculated threshold for each distributor. In relation to his own proposal, Mr. Aiken noted that the formula did not include an adjustment for historic inflation in the value of the assets; however, he commented that he would not be opposed to the inclusion of this in his approach.

Board staff carried out further analysis to estimate a more variable adjustment in its proposed approach as a function of the average number of years of the life of the plant. This was in response to Mr. Aiken's approach that recognizes distributor diversity. Staff provided a table of depreciation escalators that correlate with a variety of different average ages to reflect individual distributor age of plant. Staff calculated the cumulative Canadian CPI annual variation for the average number of years of plant. The average life of plant for each distributor was calculated by dividing the total value of the plant by annual depreciation. Using this revised inflation adjustment, the resultant threshold values ranged from 148 percent to 213 percent. Some participants observed that under staff's method, distributors with longer lived or older assets would have to exceed a higher materiality threshold than those with relatively new asset stock. However, Dr. Kaufmann observed that distributors that have older capital stock will have a lower value of reported depreciation because of the fact that the underlying assets were booked at historical cost, and submitted that if the Board does not adjust for that then those distributors will have a lower threshold. Staff noted that its proposed approach provided an empirical foundation for a threshold value which would ensure that the invoking of the capital module is an exception and not the norm.

Agreeing that invoking the module should be an exception and not a Y-factor pass through, CME submitted that to be eligible to apply and recover amounts under the capital module the CAPEX applied for must exceed the CAPEX to depreciation ratio plus a dead band, as determined by the Board. CME suggested a dead band of at least 10 percent. Mr. Shepherd noted that his proposal includes a dead band of plus or minus 50 percent of the average three-year growth percentage. Mr. Aiken suggested a dead band of 25 to 50 percent to be added directly to the threshold.

Prof. Yatchew expressed concern that if the incremental capital module does not provide adequate relief – and the threshold itself plays an important role in that – then there is a potential of incentives for distributors to front-end load their CAPEX into their test year, rather than to plan their expenditures on the basis of a more rational time distribution.

Board staff provided analysis based on RRR data that suggested that with a threshold equal to 150 percent, there would be more than 20 distributors eligible to apply and with a threshold equal to 200 percent, there would be about 10 distributors eligible. VECC observed that reviewing a capital module application may not be a simple process. It may require the review of productivity improvements inherent in capital spending and the setting of load forecasts. Therefore, VECC recommended that the Board keep this in mind when determining the threshold value. CCC observed that if in the first year the Board receives a large volume of capital module applications, then perhaps the threshold should be reconsidered.

In response to staff's 50 percent estimate for inflating depreciation expense to replacement dollars, Hydro One and the CLD estimated that adding this into the materiality threshold could translate into a decrease in ROE on an annual basis of up to 100 basis points for some distributors. Further, this impact could be cumulative over the three-year IR plan term. Therefore, Hydro One and the CLD did not support including the inflation adder to the materiality threshold, citing concerns that it would be the distributor that would have to fund this 50 percent factor that relates to capital spending. Hydro One and the CLD also observed that distributors need to reliably operate and sustain the businesses that they are licensed to conduct and submitted that if the capital module threshold, the productivity factor and the stretch factors are set too high then they may be compelled to make cost-of-service applications.

Board Policy and Rationale

The Board notes that there are clearly differences in perception as to the purpose of the incremental capital module. Ratepayer groups perceive the capital module as a mechanism aimed solely at addressing extraordinary or special CAPEX needs by distributors. The distributors, on the other hand, perceive the module as a special feature of the 3rd Generation IR architecture which would enable them to adjust rates on an on-going, as-needed basis to accommodate increases in rate base.

In the Board's view, the distributors' view is not aligned with the comprehensive price cap form of IR which has been espoused by the Board in its July 14, 2008 Report. The distributors' concept better fits a "targeted OM&A" or "hybrid" form of IR. This alternative IR form was discussed extensively in earlier consultations but was not adopted by the Board. The intent is not to have an IR regime under which distributors would habitually have their CAPEX reviewed to determine whether their rates are adequate to support the required funding. Rather, the capital module is intended to be reserved for unusual circumstances that are not captured as a Z-factor and where the distributor has no other options for meeting its capital requirements within the context of its financial capacities underpinned by existing rates.

A review of an application will test whether the applicant has passed the materiality threshold, and, if it does, will scrutinize the need for the requested incremental capital relief. Such scrutiny will entail reviewing the distributor's assumptions and planning and examining alternative options, and its overall CAPEX plan. If the application succeeds, in whole or in part, the Board will adjust rates to reflect a higher CAPEX as appropriate. It is important to note that the adjustment in rates will be linked solely to the costs of the incremental capital. Therefore, distributors should not perceive this activity as an opportunity to true up rate base for any other reason.

The incremental capital for which the Board may provide rate relief is the new capital sought in excess of the materiality threshold. The proceeding to consider an eligible distributor's application for rate relief would examine the reasonableness of the distributor's increased spending plan. If the application is approved, a rate rider would be established to reflect an amount sufficient to accommodate the portion of the approved incremental spending that exceeds the threshold amount. In calculating the rate relief, the Board has determined not to apply the half-year rule so as not to build in a deficiency for subsequent years in the term of the plan.

Distributors that receive rate relief through this module will be required to report to the Board annually on the actual amounts spent. At the time of rebasing, the Board will carry out a prudence review to determine the amounts to be incorporated in rate base. The Board will also make a determination at that time regarding the treatment of differences between forecast and actual capital spending during the IR plan term. Overspending or underspending will be reviewed at the time of rebasing.

With respect to the threshold itself, the Board believes that distributors should be able to determine whether or not they are eligible to apply with relative ease. Making that determination should not be an unduly cumbersome exercise. It should be formulaic and it should be relatively easy to populate with the required data.

With rebasing at the end of 2nd Generation IR, and before commencing 3rd Generation IR, a distributor's rates include a CAPEX component. The adequacy of such CAPEX provision in rates during 3rd Generation IR depends on whether or not the need for CAPEX during 3rd Generation IR can be met through existing rates, as adjusted under the 3rd Generation IR regime and considering organic growth. There is no dispute among participants that the price adjustment and organic growth factors should be captured in the calculation of the threshold and that not doing so would amount to "double-dipping".

A constant theme in this and earlier consultations has been the notion that there is diversity among distributors in their needs for future CAPEX. The Board sees merit in an incremental capital module that considers the diversity among the distributors, as long as it can be implemented in a manner that is not unduly cumbersome. The Board has not observed any objections to this approach.

There was considerable support for the formula presented by Mr. Aiken on behalf of LPMA and Energy Probe. That formula incorporates both the impact of the price cap and of load growth on the level of CAPEX that can be funded without additional rate relief and does this on a distributor-specific basis, reflecting both distributor diversity and the differing positions of the distributors in the asset replacement cycle. The data required to perform the calculation is easily obtainable from the distributor's most recent rebasing and IR decisions.

There was a proposal that the price adjustment factor in the formula should be the gross inflation factor, not netted for the X (productivity) factor, to incorporate the expectation for a more efficient use of capital. The Board is not persuaded of the appropriateness of this approach as it goes beyond the need to address the more immediate pressures of incremental investing.

Certain participants suggested that there should be a dead band added to the calculated materiality threshold to prevent marginal applications. The suggested levels ranged from adding 10 percent to 50 percent to the calculated percentage thresholds. The Board finds merit in the suggestion of adding a dead band. However, a high adder may be unreasonably prohibitive for distributors genuinely in need of incremental CAPEX during the term of 3rd Generation IR, as it would connote a regime that is not related to revenue requirement considerations. The Board is satisfied that a 20 percent adder is sufficient at this time.

Accordingly, the Board has determined that the appropriate CAPEX to depreciation threshold value to establish materiality for the incremental capital module should be distributor-specific and derived using the following formula:

$$\textit{Threshold Value} = 1 + \left(\frac{RB}{d}\right) * (g + PCI * (1 + g)) + 20\%$$

Where:

RB = rate base included in base rates ($);

d = depreciation expense included in base rates ($);

g = distribution revenue change from load growth (%); and

PCI = price cap index (% inflation less productivity factor less stretch factor).

Further details regarding this formula are set out in Appendix B to this Report.

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3 Tax Changes in Relation to the Z-factor

Some participants in this consultation expressed concern over the issue of the treatment of tax changes under an IR plan that uses the GDP IPI FDD as the inflation factor. The Board noted in the July 14, 2008 Report that it would be informed by the Board's decision in the EB-2007-0606/615 proceeding in relation to gas distributor incentive regulation applications in which tax as a Z-factor was being considered.

The EB-2007-0606/615 decision was issued on July 31, 2008, and concluded that a 50/50 sharing of the impact of tax changes, as applied to the tax level reflected in the Board-approved base rates, is reasonable. Therefore, 50 percent of the tax reductions would be treated as a Z-factor and ratepayers would receive 50 percent of the tax benefits that will occur from 2008 through 2012.

For purposes of the 3rd Generation IR plan, the Board has not identified any reasons to adopt an approach different than that now in place for the gas distributors.

Therefore, for 3rd Generation IR, the Board has determined that a 50/50 sharing of the impact of currently known legislated tax changes, as applied to the tax level reflected in the Board-approved base rates for a distributor, is appropriate. An approach similar to that adopted in the gas IR plans will be used to calculate the savings for purposes of the sharing. Additional details are set out in Appendix B to this Report.

Appendix A: Summary of Productivity Factor Recommendations

Table 4: Summary of Productivity Factor Recommendations from Dr. Kaufmann, Prof. Yatchew, Dr. Cronin, and Ms. Frayer

Recommendation		Supporting Assumptions for Recommended Value
Ms. Frayer, London Economics	**0.58%**	annual % changes (below) Cronin & King Study 1st Generation PBR[7] Data 1.76% 1.64% 1.70% 1.76% 1.64% PEG IR Report PEG Projection -1.3% 0.1% 0.0% -1.5% -2.6% LEI Study RRR data
Dr. Cronin	**Menu**	0.80% (avg. annual) to 1.6% -0.1% -0.1% -0.1% -0.1% -0.1% 2.11% 2.07% 2.12% 1.98% Cronin & King Study 1st Generation PBR Data
Prof. Yatchew, University of Toronto	**0.55%**	0.41% (avg. annual) 0.72% (avg. annual) PEG Study - U.S. Data
Dr. Kaufmann, Pacific Economics Group	**0.88%**	0.88 (avg. annual) 2.00% 0.20% -0.98% 0.79% -1.47% 1.00% 1.77% 0.48% 2.12% 0.00% 0.57% 2.06% 1.75% 1.08% -0.89% 2.43% 0.26% -0.09% Average annual productivity growth in the U.S. electricity distributor data is 0.72% U.S. data

1988 1989 1990 1991 1992 1993 1994 1995 1996 1997 1998 1999 2000 2001 2002 2003 2004 2005 2006 2007

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[7] The first generation electricity distribution performance-based regulation plan is detailed in the Board's January 18, 2000 RP-1999-0340 Decision with Reasons and is available on the Board's web site at http://www.oeb.gov.on.ca/OEB/Industry+Relations/OEB+Key+Initiatives/Archived+OEB+Key+Initiatives/First+Generation+Electricity+Distribution+PBR.

Appendix B: Amended Filing Guidelines

These filing guidelines supersede the filing guidelines set out in the Appendix to the July 14, 2008 Report.

Changes are highlighted for easy identification.

These filing guidelines set out the Board's expectations for applications by distributors for rate adjustments on the basis of the 3rd Generation IR mechanism.

General

The implementation of the 3rd Generation IR mechanism will occur first with rate adjustments scheduled for May 1, 2009.

The price cap adjustment will be applied to the Service Charge and Distribution Volumetric Rate (including low voltage charges for embedded distributors), net of existing rate adders and rate rebalancing adjustments as determined necessary by the Board. The price cap adjustment will not be applied to Rate Riders, Retail Transmission Service Rates, Wholesale Market Service Rate, Rural Rate Protection Charge, Standard Supply Service – Administrative Charge, Specific Service Charges, Allowances[8], Retail Service Charges or Loss Factors.

The price cap adjustment will reflect inflation less the X-factor, and an adjustment for the transition to the common deemed capital structure of 60% debt and 40% equity.

[8] Transformation and primary metering allowances and any other allowances the Board may determine.

Manager's Summary

Each application should include a completed Model, provided by the Board, and a brief Manager's Summary explaining all rate adjustments applied for. Any deviations should be thoroughly documented. Where necessary, support for applied adjustments, such as continuation of rate riders or for Z-factors, should be provided.

Incremental Capital Module

The incremental capital module has been incorporated into the 3rd Generation IR mechanism to address the treatment of new capital investment needs that arise during the IR plan term which are incremental to the materiality threshold defined below.

Eligibility Criteria for Incremental Capital Module Applications

The eligibility criteria for applications to recover amounts through rates to fund incremental capital investment needs are discussed in section 2.5 of the Board's July 14, 2008 Report, and are reproduced in Table 5 below for convenience:

Table 5: Incremental Capital Investment Eligibility Criteria

Criteria	Description
Materiality	The amounts must exceed the Board-defined materiality threshold and clearly have a significant influence on the operation of the distributor; otherwise they should be dealt with at rebasing.
Need	Amounts should be directly related to the claimed driver, which must be clearly non-discretionary. The amounts must be clearly outside of the base upon which rates were derived.
Prudence	The amounts to be incurred must be prudent. This means that the distributor's decision to incur the amounts must represent the most cost-effective option (not necessarily least initial cost) for ratepayers.

Materiality Threshold

The materiality threshold for applications to recover amounts through rates to fund incremental capital investment needs is discussed in section 2.3 of this Report. The Board has determined that the following formula is to be used by a distributor to calculate the materiality threshold that will apply to it:

$$\textit{Threshold Value} = 1 + \left(\frac{RB}{d}\right) * (g + PCI * (1 + g)) + 20\%$$

Where:

RB = rate base included in base rates ($);
d = depreciation expense included in base rates ($);
g = distribution revenue change from load growth (%); and
PCI = price cap index (% inflation less productivity factor less stretch factor).

The values for “RB” and “d” are the Board-approved amounts in the distributor’s base year rate decision.

The value for “g” is the % difference in distribution revenues between the most current complete year and the base year. For example, for distributors that were rebased in 2008:

If a distributor applies in	then “g” will be the % difference between
2009	2007 actuals and 2008 Board-approved base
Jan-Mar 2010 Apr-Dec 2010	2007 actuals and 2008 Board-approved base 2008 Board-approved base and 2009 actuals
Jan-Mar 2011 Apr-Dec 2011	2008 Board-approved base and 2009 actuals 2008 Board-approved base and 2010 actuals

An Illustration:

Assumptions:	RB	=	$100 million;
	d	=	$5 million;
	g	=	1.5% (0.015); and
	PCI	=	0.75% (0.0075).
Calculation:	$1+(\frac{100,000,000}{5,000,000})*(0.015+.0075*(1+0.015))+0.20=1.65$		
Result:	The materiality threshold (CAPEX/Depreciation) is 1.65 or 165%. That is, given the assumptions in this example, the Board expects the distributor to manage a CAPEX level of up to $8.26 million ($5 million * 1.65) before being eligible to apply to recover incremental amounts.		

Filing Guidelines

The Board expects that applications requesting relief for incremental CAPEX during the IR plan term will be accompanied by comprehensive evidence to support the claimed need, and include the following:

- An analysis demonstrating that the materiality threshold test has been met and that the amounts will have a significant influence on the operation of the distributor;
- A description of the underlying causes and timing of the capital expenditures including an indication of whether expenditure levels could trigger a further application before the end of the IR term;
- An analysis of the revenue requirement associated with the capital spending (i.e., the incremental depreciation, OM&A, return on rate base and PILs associated with the incremental capital), and a specific proposal as to the amount of relief sought;
- Justification that amounts being sought are directly related to the claimed cause, which must be clearly non-discretionary and clearly outside of the base upon which current rates were derived. This includes historical plant continuity information for each year of the IR plan term since the last Board-approved Test Year;

- Justification that the amounts to be incurred will be prudent. This means that the distributor's decision to incur the amounts represents the most cost-effective option (not necessarily least initial cost) for ratepayers;
- Evidence that the incremental revenue requested will not be recovered through other means (e.g., it is not, in full or in part, included in base rates or being funded by the expansion of service to include new customers and other load growth); and
- A description of the actions the distributor will take in the event that the Board does not approve the application.

Reporting Requirements

Distributors that receive rate relief through this module will be required to report to the Board annually on the actual amounts spent. At the time of rebasing, the Board will carry out a prudence review to determine the amounts to be incorporated in rate base. The Board will also make a determination at that time regarding the treatment of differences between forecast and actual capital spending during the IR plan term. Overspending or underspending will be reviewed at the time of rebasing

Z-Factors

Z-factors are events that are not within management's control. A distributor will be expected to supply the details of management's plans for addressing these events in support of the distributor's request for special cost recovery.

A distributor may record amounts which meet the eligibility criteria presented below for Z-factor events.

A distributor is expected to follow the guidelines listed below when applying to the Board to recover from ratepayers the amounts that the distributor has recorded. The Board may limit the recovery of certain amounts.

Eligibility Criteria for Z-factor Amounts

The eligibility criteria for applications to recover amounts in the Z-factor are discussed in section 2.6 of the Board's July 14, 2008 Report, and are summarized in Table 6 below. In order for amounts to be considered for recovery in the Z-factor, the amounts must satisfy all three criteria set out in Table 6.

Table 6: Z-Factor Amount Eligibility Criteria

Criteria	Description
Causation	Amounts should be directly related to the Z-factor event. The amount must be clearly outside of the base upon which rates were derived.
Materiality	The amounts must exceed the Board-defined materiality threshold and have a significant influence on the operation of the distributor; otherwise they should be expensed in the normal course and addressed through organizational productivity improvements.
Prudence	The amount must have been prudently incurred. This means that the distributor's decision to incur the amount must represent the most cost-effective option (not necessarily least initial cost) for ratepayers.

Materiality Threshold

The Board has determined that the following materiality thresholds will apply:

- $50 thousand for distributors with a distribution revenue requirement less than or equal to $10 million;
- 0.5% of distribution revenue requirement for distributors with a revenue requirement greater than $10 million and less than or equal to $200 million; and
- $1 million for distributors with a distribution revenue requirement of more than $200 million.

As is currently the case, the threshold must be met on an individual event basis in order to be eligible for potential recovery.

Filing Guidelines

Distributors are expected to submit evidence that the costs/revenues which were incurred / received meet the three eligibility criteria outlined above.

Distributors are expected to report events to the Board promptly and apply to the Board for any amounts claimed under Z-factor treatment with the next rate application. This will allow the Board and any affected distributor the flexibility to address extraordinary events in a timely manner. Subsequently, the Board may review and prospectively adjust the amounts claimed under Z-factor treatment.

The Board expects that any application for a Z-factor will be accompanied by a clear demonstration that the management of the distributor could not have been able to plan and budget for the event and that the harm caused by extraordinary events is genuinely incremental to their experience or reasonable expectations.

Other Matters in Relation to Z-Factors and Incremental Capital Module

Distributors will be expected to file a proposal, including the manner in which it intends to allocate the incremental revenue requirement to the various customer rate classes, the rationale for the selected approach and a discussion of the merits of alternative allocations considered.

Distributors will also be expected to file a detailed proposal including justifications to recover, through a rate rider, the Board-approved incremental revenue requirement. The proposal should specify whether the rate rider will apply on a fixed or variable basis, or a combination thereof, and the time period for collection. A detailed calculation of the rate rider(s) should be provided for each year of the IR plan term.

Accounting Treatment

Eligible **Z-factor** amounts should be included in Account 1572, "Extraordinary Event Costs", of the Board's Uniform System of Accounts (the "USoA") contained in the Accounting Procedures Handbook for electricity distributors.

Eligible **Incremental Capital Module** amounts should be recorded in Account 1508, "Other Regulatory Asset, Sub-account Incremental Capital Expenditures", of the Board's USoA contained in the Accounting Procedures Handbook for electricity distributors.

Carrying charge amounts shall be calculated using simple interest applied to the monthly opening balances in the account and recorded in a separate sub-account of this account. The rate of interest shall be the rate prescribed by the Board for the respective quarterly period for deferral and variance accounts. These prescribed rates are reviewed and updated each quarter and published on the Board's web site.

Tax Changes in Relation to the Z-factor

The treatment of tax changes is addressed in section 1 of this Report. The Board has determined that a 50/50 sharing of the impact of currently known legislated tax changes, as applied to the tax level reflected in the Board-approved base rates for a distributor, is appropriate. An approach similar to that adopted in the gas IR plans will be used to calculate the tax reduction for this purpose. The calculated annual tax reduction over the plan term will be allocated to customer rate classes on the basis of the Board-approved base-year distribution revenue. These amounts will be refunded to customers each year of the plan term, over a 12-month period, through a volumetric rate rider derived using annualized consumption by customer class underlying the Board-approved base rates.

The Model provided by the Board will include a schedule for distributors to complete that will calculate the amount to be shared and the resulting rate rider.

EB-2007-0673
Supplemental Decision on Cost Eligibility

Ontario Energy Board | Commission de l'énergie de l'Ontario

Ontario

EB-2007-0673

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, Schedule B;

AND IN THE MATTER OF cost award eligibility for interested parties in a consultation process to develop the principles and methodology of 3rd generation incentive regulation to be applied by the Board in determining electricity distribution rates effective May 1, 2009.

BEFORE: Paul Vlahos
Presiding Member

Paul Sommerville
Board Member

SUPPLEMENTAL DECISION ON COST ELIGIBILITY

On August 2, 2007, the Ontario Energy Board (the "Board") initiated a consultation process in relation to the development of the principles and methodology for the third generation incentive regulation (3rd Generation IR) mechanism for electricity distributors. At that time, interested parties were notified that cost awards would be available to eligible persons under section 30 of the *Ontario Energy Board Act, 1998* in relation to their participation in this consultation process, and that any costs awarded would be recovered from rate-regulated licensed electricity distributors. This consultation process is an ongoing one, and has already been the subject of a Decision on Cost Eligibility as well as a Decision and Order on Cost Awards in relation to work completed to the end of 2007.

The next activity eligible for cost awards in this consultation process is written comment on Board staff's proposal for 3rd Generation IR for electricity distributors. In its May 2, 2008 letter to participants inviting written comment on staff's proposal, the Board set out that the total eligible hours per eligible participant for this activity is up to 20 hours.

These comments are due May 16, 2008.

On May 5, 2008 the Board received a request for cost eligibility from the Canadian Manufacturers & Exporters (CME). On May 8, 2008 the Board received a supplemental request for cost eligibility from the Workers' Union (PWU) specifically seeking cost eligibility subject to the cost award guidelines set out by the Board in its May 2, 2008 letter for their expert's preparation of comments on the Board staff proposal. Both of these requests have been posted on the Board's web site.

This consultation has been in progress for over nine months, and has culminated in staff's proposal. At this late stage in the consultation, the Board denies CME's request for cost eligibility.

The Board made an exception for the PWU in a May 1, 2008 supplemental decision on cost eligibility for their expert's preparation, participation and reporting time for the May 6, 2008 meeting, subject to the maximum set out in the Board's April 23, 2008 letter, plus expenses. The PWU, a union that represents certain employees of some electricity distributors in Ontario, is not normally eligible for an award of costs based on the criteria set out in section 3 of the Board's *Practice Direction on Cost Awards*. However, for the reasons identified in the Board's May 1, 2008 supplemental decision, the Board has determined that the PWU is eligible for their expert's preparation of written comments on staff's proposal subject to the maximum set out in the Board's May 2, 2008 letter.

ISSUED at Toronto, May 16, 2008
ONTARIO ENERGY BOARD

Original signed by

____

Paul Vlahos
Presiding Member

Original signed by

____

Paul Sommerville
Board Member

APPENDIX A

LIST OF PARTICIPANTS

EB-2007-0673

May 16, 2008

EB-2007-0673

Ontario Energy Board

LIST OF PARTICIPANT

Revised 2008-05-16

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Ontario Energy Board
Filing Requirements for Electricity Transmission
and Distribution Applications

Ontario Energy
Board

Commission de l'énergie
de l'Ontario

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Ontario

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Ontario Energy Board

Filing Requirements
For
Electricity Transmission and Distribution Applications

Last Revised on June 28, 2012
(Originally issued on November 14, 2006)

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Ontario Energy Board

Commission de l'énergie de l'Ontario

Ontario Energy Board

Chapter 1 of the Filing Requirements For Electricity Transmission and Distribution Applications

June 28, 2012

Chapter 1 - Overview

This document provides information about the filing requirements for electricity transmission and distribution applications. It is designed to provide direction to applicants, and it is expected that applicants will comply with the filing requirements unless such compliance is not practical or in the public's interest. It is not a statutory regulation or a rule or code issued under the Board's authority. It does not preempt the Board's discretion to make any order or directive as it determines necessary concerning any of the matters raised by the applications filed.

The filing requirements are generally intended to apply to both transmitters and distributors. Unless specifically identified, the use of the words “utility”, “utilities”, “applicant” or “applicants” in this document refers to both transmitters and distributors. However, some sections, such as cost allocation in Chapter 2, are only applicable to distributors. These sections will use the word “distributor” when referring to the filer.

The purpose of this document is to provide information about several filing requirements dealing with electricity transmission and distribution applications. These include:

Chapter 2 - Filing requirements for electricity transmission and distribution companies' cost of service rate applications pursuant to section 78 of the *Ontario Energy Board Act, 1998* (the “Act”), based on a forward test year;

Chapter 3 - Filing requirements for the 3rd generation incentive regulation mechanism for electricity distributors pursuant to section 78 of the Act;

Chapter 4 - Filing requirements for leave to construct electricity transmission projects under section 92 of the Act;

Chapter 5 - Vacant;

Chapter 6 – Vacant; and

Chapter 7 - Filing requirements for applications for service area amendments under section 74(1) of the Act.

Chapter 2 details the filing requirements for a cost of service rate application based on a forward test year that the Board will require from an electricity transmission or distribution company. They set out the necessary material that should be included in a rate application. An application that fails to provide all of the elements may be considered incomplete and may not be processed until the material is provided.

Chapter 3 details the filing requirements under the incentive regulation mechanism. This approach will be used for electricity distributors when there is no requirement to file a cost of service rate application.

Chapter 4 details the filing requirements for the approval of leave to construct electricity transmission projects under section 92 of the Act for the construction, expansion, or reinforcement of electricity transmission facilities greater than 2 km in length.

Chapter 5 formerly contained filing requirements for the approval of a capital budget for a transmission project in a rate application or for the approval of projects under section 92 of the Act prior to the approval of an Integrated Power System Plan. Any requirements that remain applicable have been included in the recent update to Chapter 4. Chapter 5 is now vacant.

Chapter 6 formerly contained filing requirements on conservation and demand management ("CDM"). These have been superseded by the CDM Code, and the April 26, 2012 CDM Guidelines issued under EB-2012-0003. Chapter 6 is currently vacant.

Chapter 7 contains the filing requirements for service area amendment applications under section 74 (1) of the Act, which were last issued on March 12, 2007.

Completeness and accuracy of an application

An application to the Board by a regulated company should provide sufficient detail to enable the Board to make a determination as to whether the proposals are just and reasonable. The material presented is the applicant's evidence and the onus is on the applicant to prove, for example, the need for and reasonableness of the costs that are the basis of proposed new rates (Chapter 2). A clearly written application that demonstrates the need for the proposed rates, complete with sufficient evidence and justification for those rates, is essential to facilitate an efficient regulatory review and a timely decision. The same holds true for any other requests that form the basis of an application pursuant to other chapters of these filing requirements. The applicant must, at a minimum, meet all of the applicable filing requirements. However, the applicant has the responsibility to file additional material where necessary to prove its case.

The examination of an application and the subsequent decision are based only on the evidence filed in that case. This ensures that all interested parties to the proceeding have an opportunity to see the entire record, participate meaningfully in the proceeding and understand the reasons for a decision. Consequently, a complete and accurate evidentiary record is vital.

The purpose of the interrogatory process is to test the evidence before the Board, and not to seek information that should have been provided in the original application. The Board will consider an application complete if it meets all of the applicable filing requirements. Applicants must also be cognizant of the need for accuracy and consistency of the information or data presented in their applications. Applicants must ensure that information and data is consistent across all exhibits, appendices and models. If an application does not meet all of these requirements or if there are inconsistencies identified in the information or data presented, the applicant must provide an explanation as to why this is the case. Based on this explanation, the Board will assess whether or not the application can proceed.

Certification of Evidence

Each application shall include a certification from a senior officer of the applicant that the evidence filed is accurate to the best of his/her knowledge or belief.

Updating an Application

When changes or updates to a filing are necessary, a thorough explanation of the changes must be provided, along with revisions to the affected evidence and related schedules. This process is contemplated in Rule 11.02 of the *Rules of Practice and Procedure*. When these changes or updates are contemplated late in a proceeding, applicants should proceed with the update only if there is a material change to the evidence already before the Board. Rule 11.03 states that any such updates should clearly indicate the date of the revision and the part revised.

Interrogatories

The Board is aware of the number of interrogatories that the existing process can generate. The frequent requirement for a large number of interrogatories suggests that applicants and interested parties do not have a common understanding of the information required to support an application. The Board advises applicants to strategically consider the clarity of the evidence, to reduce the need for interrogatories. The Board also advises parties to carefully consider the relevance and materiality of information before requesting it through an interrogatory

Where an applicant is requested by a party to file information that the applicant believes is not relevant to the proceeding, the applicant may file and serve a response to the interrogatory that sets out the reasons for the applicant's belief that the requested information is not relevant. This process is contemplated in Rule 29 of the *Rules of Practice and Procedure* and applies to all interrogatories.

In order to facilitate an efficient review of interrogatories and responses, the filing of interrogatories and responses must be sorted by issue. (For example, all interrogatory responses on test year capital budget arising from an application under Chapter 2, should be grouped together, regardless of which party submitted the interrogatory.) In the absence of a Board-approved Issues List, parties must sort their interrogatories and responses by topic as outlined in the exhibits in this filing requirement document. This process is also contemplated in Rule 29 of the *Rules of Practice and Procedure* and applies to all interrogatories.

Confidential Information

The Board relies on full and complete disclosure of all relevant material in order to ensure that its decisions are well-informed. The Board recognizes that applicants may consider some of that information to be confidential and may wish to request that it be protected. In such cases, the relevant rules in the Board's *Rules of Practice and Procedure* and the procedures set out in the Board's *Practice Direction on Confidential Filings* (the "Practice Direction") are to be followed by all participants in a proceeding before the Board, unless otherwise directed by the Board.

The onus is on the applicant or entity requesting confidential treatment to demonstrate to the satisfaction of the Board that confidential treatment is warranted. It is the Board's expectation that a party will make every effort to limit the scope of its confidentiality requests to an extent commensurate with the commercial sensitivity of the information at issue or with any legislative obligations of confidentiality or non-disclosure. The applicant or entity making such a request must prepare meaningful redacted documents or summaries so as to maximize the information that is available on the public record. This will provide all interested parties with a fair opportunity to address the issue and permit the Board to provide meaningful and well-documented reasons for its decision.

The applicant or entity requesting confidential treatment must address such requests to the Board Secretary and include the following items as set out in the Practice Direction. The applicant should review the Practice Direction in order to ensure that all requirements related to confidential information have been met:

- A cover letter indicating the reasons for the confidentiality request;

- A confidential, un-redacted version of the document containing all of the information for which confidentiality is requested and which is identified by either shading or other easily identifiable means. If confidential treatment is requested in relation to the entire document, the document should be printed on coloured paper; and
- A non-confidential, redacted version of the document from which the information that is the subject of the confidentiality request has been deleted or stricken, or, where the request for confidentiality relates to the entire document, a non-confidential description or summary of the document.

A copy of the cover letter requesting confidentiality, together with the non-confidential version or non-confidential description of the document (as applicable) must be served on all parties to the proceeding, and will be placed on the public record.

The Board and parties to a proceeding are required to devote additional resources to the administration, management and adjudication of confidentiality requests and confidential filings. Applicants should ensure that filings for which they intend to request confidential treatment are clearly relevant to the proceeding, whether the information is being filed as part of an application or in response to an interrogatory. An illustrative list of the types of information that the Board has previously assessed or maintained as confidential is set out in Appendix B of the Practice Direction.

Parties should also take note of the requirements related to relevance of interrogatories outlined in this chapter, which are also applicable to information which is requested and raises confidentiality concerns. Parties should give particular significance to the relevance of interrogatories in relation to confidential filings given the administrative issues associated with the management of those filings.

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Chapter 2 of the Filing Requirements For Electricity Transmission and Distribution Applications

June 28, 2012

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Chapter 2 Filing requirements for electricity transmission and distribution companies’ cost of service rate applications, based on a forward test year

2.0 Preamble

The Ontario Energy Board establishes the rates and charges for electricity transmission and distribution companies using a combination of annual incentive regulation mechanism (“IRM”) adjustments and periodic cost of service (“cost of service” or “CoS”) reviews. For a cost of service review, forecasted test year data is normally used. Filing requirements for IRM rate applications are provided in Chapter 3 of this document.

The use of the phrase “Board-approved” in these filing requirements typically refers to the set of data used by the Board as the basis for approving the most recent cost based rates. It does not mean that the Board, in fact, “approved” any of the data, but only that the final approved rates were based on that data.

The filing requirements contained in this chapter outline all of the relevant information necessary for a complete cost of service-based application. Sections 2.1 and 2.2 address issues related to certain non-standard applications. Section 2.1 addresses the matter of an applicant seeking to make a cost of service rebasing application prior to the end of the IRM term. Section 2.2 addresses the issue of an applicant seeking an effective date other than May 1 of the test year. Beginning with Section 2.3, the filing requirements for the application itself are outlined. Section 2.3 provides an Introduction, including an overview of general requirements and information on key planning parameters. Sections 2.4 to 2.12 provide requirements for each of the major exhibits covered by the application (e.g., Section 2.6 addresses operating revenue, while Section 2.10 addresses cost allocation).

The various appendices referenced in the chapters are linked to each of these sections and provide schedules to be completed by the applicant to facilitate the filing of all required information (e.g., Appendix 2-P Cost Allocation provides tables related to Revenue-to-Cost Ratios and Test Year Revenue Impacts). These appendices are available in Excel format on the Board’s web site and should be completed by applicants and filed as part of a CoS application.

Any application made pursuant to section 92 (i.e. Leave to Construct) of the *Ontario Energy Board Act, 1998* (the “OEB Act”) is subject to the requirements of chapter 4 of the Filing Requirements (see Section 2.5 dealing with capital budgets for projects with construction commencing in the Test Year).

Applicants should review Chapter 1 of this document which provides an overview of the various chapters in this document and addresses the Board’s expectations on certain generic matters such as the completeness and accuracy of an application and confidential filings.

2.1 Cost of Service Application in Advance of Scheduled Application

On April 20, 2010, the Board issued a letter entitled *Early Rebasing Applications* addressing the issue of electricity distributors intending to file rate applications to have their rates set through a cost of service proceeding earlier than would normally be scheduled in the multi-year plan for cost of service and IRM rate applications. Currently, it is normally intended that an applicant will file for a cost of service rebasing once every four years, followed by three years of IRM rate adjustments.

The letter noted that, while the Board's rate-setting policies are such that distributors are expected to be able to adequately manage their resources and financial needs during the term of their IRM plan, the Board's multi-year rate setting approach does contemplate that some distributors may legitimately need to have their rates rebased earlier than originally scheduled, by making provision for an "off-ramp". The Board stated that the conditions under which the "off-ramp" would be applicable reflected the Board's view of circumstances that would justify a departure from the normal 4-year plan schedule and necessitate an early cost of service rebasing.

The letter stated that a distributor seeking to have its rates rebased in advance of its next regularly scheduled cost of service proceeding, notwithstanding that the "off ramp" conditions have not been met, must justify in its cost of service application why an early rebasing is required. Specifically, the distributor would be expected to demonstrate clearly why and how it could not adequately manage its resources and financial needs during the remainder of its IRM plan period. The letter further advised distributors that the panel of the Board hearing such an application may consider it appropriate to determine, as a preliminary issue, whether the application for rebasing is justified or whether the application as framed should be dismissed. Distributors were also advised that the Board might, where an application for early rebasing did not appear to be justified, disallow some or all of the regulatory costs associated with the preparation and hearing of that application.

The Board issued early rebasing decisions related to three such applications for the 2011 rate year and one such application for the 2012 year. It is recommended that distributors contemplating an early rebasing application for 2013 rates first review these decisions before deciding to proceed with such an application.

2.2 Seeking Approval for an Effective Date Other Than May 1 of the Test Year

On April 15, 2010, the Board issued a letter entitled *Alignment of Rate Year with Fiscal Year for Electricity Distributors*. In the letter, the Board concluded it would be appropriate to consider the merits of an alignment of the rate year with the fiscal (calendar) year for distributors on a case-by-case basis upon receipt of an application for that purpose as part of a distributor's cost of service rate application.

The letter further stated that the Board expected the distributor to include in such an application an analysis of the benefits and ratemaking implications, if any, of the proposed alignment. Appendix B of the letter contained examples of the issues that were to be addressed.

If a January 1st implementation date is being requested in order to align the rate year with the fiscal year, the Board would normally expect such applications to be filed no later than by the end of April prior to the test year in order to allow sufficient time for the review of the application.

2.3 Introduction

The basic format of an application for a forward test year cost of service filing should consist of the following nine Exhibits:

Exhibit 1	Administrative Documents
Exhibit 2	Rate Base
Exhibit 3	Operating Revenue
Exhibit 4	Operating Costs
Exhibit 5	Cost of Capital and Capital Structure
Exhibit 6	Calculation of Revenue Deficiency/Sufficiency
Exhibit 7	Cost Allocation
Exhibit 8	Rate Design
Exhibit 9	Deferral and Variance Accounts

These exhibits correspond with the elements of a cost of service application, which is intended to establish rates that recover a revenue requirement based on an estimate of demand for the test year. A schematic of the elements of a cost of service application is provided in Appendix 2-X.

If any significant element of these filing requirements is not included in the filing, the application may be deemed by the Board to be incomplete and may not be processed until the missing information is provided.

Other exhibits may also be included in an application to document other proposals for which the applicant is seeking Board review and approval. These could be related to, for example, Lost Revenue Adjustment Mechanism and Shared Savings Mechanism recoveries. Guidance on the material to be included in such exhibits is provided through applicable guidelines or other documentation that the Board may provide, or that may be contained in applicable legislation or regulation.

2.3.1 Key References

The references listed below are key to interpreting these Filing Requirements:

- Generally Accepted Accounting Principles ("GAAP");
- International Financial Reporting Standards ("IFRS");
- *Report of the Board on the Transition to International Financial Reporting Standards*, July 28, 2009 and implementation update, outlined in section 2.3.5 below;
- *Addendum to Report of the Board: Implementing IFRS in an Incentive Rate Mechanism Environment* (EB-2008-0408), June 13, 2011;
- The Board's *Accounting Procedures Handbook ("APH")* and Uniform System of Accounts ("USoA"), any subsequent updates and Frequently Asked Questions;
- *Report of the Board on the Cost of Capital for Ontario's Regulated Utilities* (EB-2009-0084), December 11, 2009 and any subsequent updates;
- *Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors*, July 14, 2008;
- Supplemental Report, and Addendum, of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors, September 17, 2008 and January 28, 2009;
- *Cost Allocation Informational Filing Guidelines for Electricity Distributors*, November 15, 2006;
- *Application of Cost Allocation for Electricity Distributors*, November 28, 2007;
- *Review of Electricity Distribution Cost Allocation Policy: Report of the Board* (EB-2010-0219), March 31, 2011;
- *Report of the Board on Electricity Distributor's Deferral and Variance Account Review Initiative* (EB-2008-0046), July 31, 2009;
- *Guideline G-2011-0001:Smart Meter Funding and Cost Recovery – Final Disposition*, December 15, 2011, and any subsequent updates;
- *Green Energy and Green Economy Act* Initiatives outlined in Section 2.3.4 below;
- *Guidelines for Electricity Distributor Conservation and Demand Management* (EB-2012-0003), April 26, 2012;
- *Guideline G-2008-0001: Electricity Distribution Retail Transmission Service Rates*, October 22, 2008 and any subsequent updates;
- *Asset Depreciation Study for Use by Electricity Distributors* (EB-2010-0178), (the "Kinectrics Report"), July 8, 2010;
- Board letter of April 15, 2010, providing guidance to electricity distributors on the alignment of the rate year with fiscal year (EB-2009-0423);

- Board letter of April 12, 2012, providing an update on the options established in the June 22, 2011 cost of service filing requirements for the calculation of the allowance for working capital for the 2013 rate year; and
- Board letter of April 30, 2012, providing guidance to electricity distributors on the impact of the decision to defer the mandatory date for the implementation of IFRS.

2.3.2 General Requirements

The requirements outlined below are general requirements that are applicable throughout the application:

- Written direct evidence is to be included before data schedules;
- Average of the opening and closing fiscal year balances must be used for items in rate base;
- Total Capitalization (debt and equity) must equate to Total Rate Base;
- Data for the following years, at a minimum, must be provided:
    - Test Year = Prospective Rate Year;
    - Bridge Year = Current Year;
    - Three Most Recent Historical Years (or number of years necessary to provide actuals back to and including the most recent Board Approved Test Year, but not less than three years); and
    - Most recent Board Approved Test Year.
- A statement is to be provided as to when the forecast was prepared and when it was approved by the utility's management and/or Board of Directors for use in the application;
- Multi-year data for each of the above-referenced years is to be presented on the same sheet for the summary/main schedules;
- A detailed year-over-year variance analysis is to be provided between the Test Year and Bridge Year, the Historical Year(s) and the last Board Approved Test Year, including reasons/drivers of variances and the contribution of each driver towards the total year-over-year variance;
- Calculations of revenue sufficiency/deficiency;
- For Board-prescribed values, such as ROE and deemed debt rates, the most recent values available from the Board are to be used as applicable with an accompanying statement that they will be updated as required. If an applicant is proposing to use values and methodologies different from the standard Board policy and practice, this proposal should be clearly stated and reasons/ supporting evidence provided;

- The most recent Board-approved RPP and an estimate for non-RPP (at the time of filing) is to be used for the electricity commodity price;
- Changes to accounting policies made since the applicant's last cost of service filing are to be identified and a summary of the impacts of any such changes is to be provided (these include any changes on adoption of IFRS for which the Board has provided further direction);
- Changes in legal organization or control must be identified;
- Changes in tax status (e.g. a change from a corporation to a limited partnership) must be disclosed;
- Any orders or directions outstanding from previous Board Decisions or Orders are to be identified and addressed;
- Documents are to be provided in a text-searchable Adobe PDF format; and
- Tables should also be provided in Excel spreadsheet format.

2.3.3 Green Energy Act Requirements

A distributor filing a cost of service rate application for 2012 or subsequent rate years must file with the Board a Green Energy Act Plan ("GEA Plan") as part of such an application. The requirements for the filing are described in the Board's May 17, 2012 update to the *Filing Requirements: Distribution System Plans – Filing Under Deemed Conditions of Licence* (EB-2009-0397).

As permitted by Section 2.2 of the May 17, 2012 update to the EB-2009-0397 Filing Requirements, the Board may permit a utility to defer the filing of a GEA plan. A utility that wishes to request a deferral should specifically include that request in its cost of service application, together with a detailed explanation of why the deferral has been requested, and a proposal for when the GEA plan will be filed.

A distributor should also consult recent decisions issued by the Board related to GEA expenditures as well as the following documents with respect to requirements arising from amendments to the OEB Act made by the *Green Energy and Green Economy Act, 2009* and related Board initiatives that may affect their 2013 cost of service applications:

- *Distribution System Code Amendments* (EB-2009-0077), October 21, 2009.

    The Board's amendments to the *Distribution System Code* which revised the Board's approach to assigning cost responsibility between distributors and generators in relation to the connection of renewable generation facilities.

- *Conservation and Demand Management Code ("CDM Code")* (EB-2010-0215), Sept. 16, 2010.

The Board's CDM Code is designed to ensure that distributors meet their CDM targets in a way which is cost effective and provides value to ratepayers.

- *Guidelines for Electricity Distributor Conservation and Demand Management ("CDM Guidelines") (EB-2012-0003)*

  The CDM Guidelines provide specific guidance on certain provisions in the CDM Code and identify the evidence that should be filed by distributors in support of an application for Board-Approved CDM programs. In addition, the CDM Guidelines provide details on the Lost Revenue Adjustment Mechanism related to CDM programs implemented under the CDM Code and for persisting lost revenues for pre-2011 CDM programs.

- *Electricity Conservation and Demand Management Targets (EB-2010-0216),* June 22, 2010 and *Decision and Order (EB-2010-0215/EB-2010-0216)* March 14, 2011.

- *Framework for Determining the Direct Benefits Accruing to Customers of a Distributor under Ontario Regulation 330/09* (EB-2009-0349), June 10, 2010.

  Section 79.1 of the OEB Act provides for rate protection for customers of a distributor that incurs costs to make an eligible investment for the connection of qualifying generation facilities. The Board Report sets out a framework for the Board's approach to the determination of the "direct benefits" that accrue to those customers as a result of all or part of the eligible investment made or planned to be made by the distributor. This will represent the allocation of eligible investment costs to the distributor's ratepayers, with the remaining costs allocated to provincial ratepayers.

  A distributor that incurs costs to make an eligible investment shall provide a calculation of the direct benefits of that investment accruing to the distributor's customers for the test year, consistent with the Board Report, as well as the remaining eligible investment costs to be recovered from provincial ratepayers.

- *Decision and Order with Respect to a microFIT Generator Rate* (EB-2009-0326), February 23, 2010.

  In its Decision and Order issued February 23, 2010, the Board established a service classification for microFIT Generation accounts, which is to be used by all licensed distributors. On March 17, 2010, the Board issued its Rate Order, which approved a single province-wide fixed monthly charge for all electricity distributors related to the microFIT Generator rate class at $5.25 per month, effective September 21, 2009.

A distributor should include revenue arising from this charge as "Other Revenue" in its application.

- *Filing Requirements for Transmission Project Development Plans* (EB-2010-0059), August 26, 2010;

  This document sets out the policy of the Board for a framework for new transmission investment in Ontario, in particular with regard to transmission project development planning and describes how project development planning will work in conjunction with existing Board processes for licensed transmitters.

- *The Regulatory Treatment of Infrastructure Investment in Connection with the Rate-regulated Activities of Distributors and Transmitters in Ontario* (EB-2009-0152), January 15, 2010.

  The regulatory framework set out in this Report builds on the Board's rate-making framework by augmenting "conventional" cost recovery mechanisms with a range of "alternative" cost recovery mechanisms designed to facilitate appropriate infrastructure investment by distributors and transmitters.

- *Guidelines for Regulatory and Accounting Treatments for Distributor-Owned Generation Facilities* (G-2009-0300), September 15, 2009.

  These Guidelines describe the ownership scenarios available in relation to the ownership of generation and energy storage facilities described in section 71(3) of the OEB Act ("qualifying facilities") and set out the regulatory and accounting requirements applicable to each scenario. Qualifying facilities may be owned directly by a distributor, or may be owned by an affiliate of the distributor. Under the affiliate ownership scenario, a distributor would need only to review its policies, procedures and processes to ensure compliance with the *Affiliate Relationships Code for Electricity Distributors and Transmitters.*

  The ownership and operation of qualifying facilities is not a rate-regulated activity. Accordingly, if a distributor chooses to own and operate a qualifying facility directly as part of its business, costs would not be recovered through rates and a regulatory return would not be earned on the investment. For rate setting purposes, the distributor would need to file financial information in its rate application that clearly delineates the distributor's regulated activities from its non-rate related activities, as outlined in the Guidelines. For greater clarity, the distributor would need to file financial information for the consolidated utility, and individual statements for rate regulated activities and non-rate regulated activities on a pro-forma basis for the test period. By individual statements, the Board intends that separate financial information should be filed, not separate audited financial statements.

- Distributor-owned Generation (EB-2009-0411) Notice of Amendments to Codes, March 11, 2010;

  The Board issued amendments to the *Distribution System Code* and the *Affiliate Relationships Code for Distributors and Transmitters* ("ARC") to keep pace with the fact that electricity distributors are now permitted to own qualifying facilities. The amendments provide for certain provisions of the ARC to no longer apply in terms of dealings between a distributor and an affiliate in relation to activities associated with qualifying facilities. Also, the amendments ensure that distributors treat their own generation facilities in the same manner as they would treat generation facilities owned by third parties.

A distributor should incorporate a separate section in its application providing an overview of any proposals with respect to renewable generation connection plans, or smart grid plans that will have an impact on the application. This overview should summarize the key elements of any proposals made and their impacts on the application. These key impacts should also be broken out separately from the remaining costs in the relevant sections of the application (e.g. OM&A impacts arising from a GEA plan should be identified separately from the remaining OM&A costs, as discussed subsequently). A proposal seeking approval for a GEA plan should also clearly identify the period for which the distributor is seeking prudence review and approval, and the distributor's proposal for how approved GEA plan costs are to be recovered (e.g., rate adder, rate rider, deferral/variance account).

2.3.4 Transition to International Financial Reporting Standards ("IFRS"), United States Generally Accepted Accounting Principles ("USGAAP"), or an Alternate Accounting Standard

Applicants should refer to the following documents for detailed guidance relating to the use of IFRS in application filings:

- Impact of the Decision to Defer the Mandatory Date for the Implementation of IFRS to January 1, 2013 by the Canadian Accounting Standards Board, Board letter dated April 30, 2012;
- *Report of the Board: Transition to IFRS;* dated July 28, 2009;
- *Addendum to Report of the Board: Implementing IFRS in an Incentive Rate Mechanism Environment (*the "Addendum"), dated June 13, 2011.

- *Asset Depreciation Study for the Ontario Energy Board*, Kinectrics Inc. for distributors sponsored by the Board dated July 8, 2010; and
- Clarification letter regarding accounting for overhead costs associated with capital work, dated February 24, 2010.

For those applicants that must adopt IFRS for financial reporting purposes by January 1, 2013, 2013 cost of service applications must be filed on the basis of Modified IFRS ("MIFRS").

For those applicants that adopted IFRS on January 1, 2012 for financial reporting purposes, the date of transition is January 1, 2011. For those applicants that adopted IFRS on January 1, 2013 for financial reporting purposes, the date of transition is January 1, 2012.

Per the Board's letter of April 30, 2012, 2013 cost of service application are to be filed on the basis of MIFRS, except for those seeking the Board's approval to adopt USGAAP or Accounting Standards for Private Enterprise ("ASPE") as addressed by the Addendum. For MIFRS applications, the applicants must provide a summary of the dollar impacts of MIFRS to each component of the revenue requirement (e.g. rate base, operating costs, etc), including the overall impact on the proposed revenue requirement. Accordingly, the applicants must identify financial differences and resulting revenue requirement impacts arising from the adoption of MIFRS accounting.

Applicants should provide the following information:

- If an applicant chooses to adopt IFRS for financial reporting in 2012, in its 2013 cost of service application it must file information for the year prior (i.e., 2011 - the historic year) in both CGAAP and modified IFRS format, and provide the bridge year (2012) and the forecasts for the test year (2013) information in modified IFRS. The years required to be filed prior to the historic year 2011 may be provided in CGAAP only.

- If an applicant chooses to adopt IFRS for financial reporting in 2013, in its 2013 cost of service application it must provide the required actual years (2011) and the bridge year (2012) in CGAAP based format. An applicant must present modified IFRS based forecasts for the bridge (2012) and test years (2013).

The Board requires a utility that adopts USGAAP or an accounting standard other than IFRS, in its first cost of service application following the adoption of the new accounting standard, to provide the following:

1. evidence of the eligibility of the utility under the relevant securities legislation to report financial information using that standard;
2. a copy of the authorization to use the standard from the appropriate Canadian securities regulator (if applicable); and

3. evidence demonstrating the benefits and potential disadvantages to the utility and its ratepayers of using the alternate accounting standard for rate regulation.

Regardless of the accounting standard used in the application, the applicant must provide a summary of changes to its accounting policies made since the applicant's last cost of service filing (e.g. capitalization of overhead, capitalization of interest, depreciation, etc.). Revenue requirement impacts of any change in capitalization policy must be specifically and separately quantified.

2.4 Exhibit 1. Administrative Documents

The administrative documents identified in this section provide the background and summary to the case as filed. Administrative documents consist of four sections:

1) Administration;
2) Overview of the filing;
3) Financial information; and
4) Materiality thresholds.

2.4.1 Administration

This section should include the following:

- Table of Contents;
- Application;
- Statement as to which publication(s) the applicant proposes that notice should appear, whether it is a paid publication or not and the readership and circulation numbers;
- Statement as to when the distributor believes the Board's rate order would be required in order to achieve rate implementation by the requested date;
- Contact information. The primary contact for the application may be a person within the applicant's organization other than the primary licence contact. The Board will communicate with this person during the course of the application. After completion of the application, the Board will revert communication to the primary licence contact;
- List of specific approvals requested. All approvals including accounting orders which the applicant is seeking should be separately identified in this exhibit and clearly documented in the appropriate section of the application;
- Statement as to whether or not the distributor has had any transmission assets (> 50kV) deemed previously by the Board as distribution assets and whether or not

there are any such assets for which the distributor is seeking Board approval to be deemed as distribution assets in the present application;

- Proposed Issues List;
- Accounting Orders and List of any departures from the Uniform System of Accounts including references to Accounting Orders;
- Description of applicant's operating environment:
    - General description and map showing where the utility operates within the province, and the communities serviced by the utility. A utility may provide more detailed geographic and/or engineering maps where these may be useful to understand parts of the application, such as a capital expansion or replacement program;
    - A list of neighbouring utilities;
    - A description of whether the utility is a host utility (i.e. transmitting electricity to another distributor's network at distribution-level voltages) and/or an embedded distributor (i.e. receiving electricity at distribution-level voltages from any host distributor). The utility should identify the embedded and/or host distributor(s). Partially embedded status should also be clearly identified, including the percentage of load that is supplied through the host distributor;
- Corporate and Utility Organizational Structure:
    - High-level utility organization chart, showing the main units and executive and senior management positions within the utility;
    - Corporate Entities Relationship Chart, showing:
        - the organization of any associated or affiliated entities with respect to each other;
        - the extent to which the parent company is represented on the utility company board;
        - the reporting relationships between utility management and parent company officials;
        - the services and the nature of the services provided to/by affiliated entities; and
        - any shared services among the affiliated entities, including the extent to which the applicant is a "virtual" utility;
    - Planned changes in corporate or operational structure and rationale for organizational change and estimated cost impact;
    - If an applicant is conducting non-utility businesses, such as generation, it must confirm that the accounting treatment it has used has segregated all of these activities from its rate-regulated activities. Distributors owning generation facilities should consult the Board's *Guidelines: Regulation and*

Accounting Treatments for Distributor-Owned Generation Facilities G-2009-0300, September 15, 2009;

- Identification of Board Directives from any previous Board Decisions and/or Orders. The applicant should clearly indicate how these are being addressed in the current application (e.g. filing of a study as directed in a previous Decision); and
- Reference to the applicant's Conditions of Service. The applicant does not need to file its Conditions of Service, but should provide a reference to where its Conditions of Service are publicly available (e.g. on the utility's website), and confirm that this is the current version. The utility should identify if there are any rates and charges documented in its Conditions of Service. If there are changes to its Conditions of Service that would change as a result of approval of the application, the applicant must identify all such changes.

2.4.2 Overview

This section should include the following:

- Summary of Application (purpose, need, timing and key elements of the application and typical customer impact by customer class);
- Identification of accounting standard for financial reporting purposes under which the applicant has filed its rate application, IFRS, USGAAP, etc;
- Budget Overview (Capital & Operating):
  - Budget directives and guidelines; and
  - Economic assumptions used;
- Changes in methodology from previous applications or established Board practice or policy (e.g. accounting, normalization, etc.);
- Schedule of overall revenue sufficiency/deficiency;
- Schedule providing the most recent Board-approved revenue requirement and breakdown (i.e. OM&A, depreciation, taxes or PILs (grossed up), return and revenue offsets); and
- Revenue Requirement Work Form. The link on the Board's website may be used to access this work form provided in Microsoft Excel format.

2.4.3 Financial Information

This section should include the following:

- Audited Financial Statements of the utility (non-consolidated from affiliated companies) for which the application has been made, for the two most recent historical years (i.e. both year's statements must be filed, covering three years of historical actuals). If the statements are not available at the time of filing, they must be provided as soon as they are available;
- *Pro Forma* Financial Statements for the Bridge and Test Years;
- Detailed reconciliation of the financial results shown in the Annual Reports/ Audited Financial Statements with the regulatory financial results filed in the application including a reconciliation of the fixed assets, for example in order to separate non-utility businesses. This should include the identification of any deviations between the Annual Reports/Audited Financial Statements and the regulatory financial statements that are being proposed including the identification of any prior Board approvals for such deviations that may exist;
- Annual Report and Management's discussion and analysis, for the most recent year, of the parent company;
- Rating Agency Report(s), if available; and
- Prospectuses, information circulars, etc. for recent and planned public issuances.

2.4.4 Materiality Thresholds

The applicant must provide justification for changes from year to year to its rate base, capital expenditures, OM&A and other items above a materiality threshold. The materiality thresholds differ for each applicant, depending on the magnitude of the revenue requirement.

Unless a different threshold applies to a specific section of these Filing Requirements, the default materiality thresholds are as outlined in the *Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors of September 17, 2008* (EB-2007-0673) and are reproduced below:

- $50,000 for a distributor with a distribution revenue requirement less than or equal to $10 million;
- 0.5% of distribution revenue requirement for a distributor with a distribution revenue requirement greater than $10 million and less than or equal to $200 million; and
- $1 million for a distributor with a distribution revenue requirement of more than $200 million.

If an applicant believes that an alternative threshold would be appropriate to its specific circumstances, it is free to propose such an alternative, with appropriate justification, in its application.

2.5 Exhibit 2. Rate Base

This exhibit includes information on:

1) Rate Base;
2) Capital Expenditures; and
3) Service Quality and Reliability Performance.

2.5.1. Rate Base

2.5.1.1 Overview

For rate base, the applicant must include the opening and closing balances, and the average of the opening and closing balances for gross assets and accumulated depreciation. Rate base shall also include an allowance for working capital.

At a minimum, the filed material in support of the requested rate base must include data for the Historical Actuals, Bridge Year (actuals to date and balance of year as budgeted), and Test Year.

Continuity statements and year-over-year variance analyses must be provided. Continuity statements must provide year-end balances and include interest during construction, and all overheads. Variance analyses must provide a written explanation for rate base-related material when there is a variance greater than the applicable materiality threshold.

If continuity statements have been re-stated for the purposes of the application, the utility must provide a thorough explanation for the restatement and provide a reconciliation to the original statements.

The following comparisons must be provided:

- Historical Board-approved vs. Historical Actual (for most recent historic Board-approved year);
- Historical Actual vs. preceding Historical Actual (for the relevant number of years);
- Historical Actual vs. Bridge; and
- Bridge vs. Test Year.

The information outlined in Appendix 2-B should be provided for each year, in both the application material and in working Microsoft Excel format.

2.5.1.2 Gross Assets – Property Plant and Equipment

The applicant must provide the following information:

- Breakdown by function (transmission plant, distribution plant, general plant, other plant) for required statements and analyses;
- Detailed breakdown by major plant account for each functionalized plant item. For the Test year, each plant item should be accompanied by a written description;
- Summary of an incremental capital module adjustment, including what was approved and what was spent, if the applicant received approval for an incremental capital module adjustment as part of a previous 3rd generation IRM application;

For an applicant that adopted IFRS on January 1, 2012 for financial reporting purposes, the applicant must establish the continuity of historic cost by using the December 31, 2010 regulatory gross assets of property, plant and equipment as the opening January 1, 2011 regulatory gross assets. The applicant must provide schedules (including Appendix 2-B, Fixed Asset Continuity Schedule) which must identify the following details to substantiate the continuity of historic cost for regulatory purposes:

- December 31, 2010 regulatory gross assets of property, plant and equipment, by asset class; and
- January 1, 2011 regulatory gross assets of property, plant and equipment, by asset class.

For an applicant that adopts IFRS on January 1, 2013 for financial reporting purposes, the applicant must establish the continuity of historic cost by using the December 31, 2011 regulatory gross assets of property, plant and equipment as the opening January 1, 2012 regulatory gross assets. The applicant must provide schedules (including Appendix 2-B, Fixed Asset Continuity Schedule) which must identify the following details to substantiate the continuity of historic cost for regulatory purposes:

- December 31, 2011 regulatory gross assets of property, plant and equipment, by asset class; and
- January 1, 2012 regulatory gross assets of property, plant and equipment, by asset class.

2.5.1.3 Accumulated Depreciation

Continuity statements should be reconcilable to the calculated depreciation expenses (under Exhibit 4 – Operating Expenses) and presented by asset account.

For an applicant that adopted IFRS on January 1, 2012 for financial reporting purposes, the applicant must establish the continuity of historic cost by using the December 31, 2010 regulatory accumulated depreciation as the opening January 1, 2011 regulatory accumulated depreciation. The applicant must provide schedules (including Appendix 2-B, Fixed Asset Continuity Schedule) which must identify the following details to substantiate the continuity of historic cost for regulatory purposes:

- December 31, 2010 regulatory accumulated depreciation, by asset class; and
- January 1, 2011 regulatory accumulated depreciation, by asset class.

For an applicant that adopted IFRS on January 1, 2013 for financial reporting purposes, the applicant must establish the continuity of historic cost by using the December 31, 2011 regulatory accumulated depreciation as the opening January 1, 2012 regulatory accumulated depreciation. The applicant must provide schedules (including Appendix 2-B, Fixed Asset Continuity Schedule) which must identify the following details to substantiate the continuity of historic cost for regulatory purposes:

- December 31, 2011 regulatory accumulated depreciation, by asset class; and
- January 1, 2012 regulatory accumulated depreciation, by asset class.

2.5.1.4 Allowance for Working Capital

In a letter dated April 12, 2012, the Board provided an update to electricity distributors and transmitters on the options established in the June 22, 2011 cost of service filing requirements for the calculation of the allowance for working capital for the 2013 rate year. The applicant may take one of two approaches for the calculation of its allowance for working capital: (1) the 13% allowance approach; or (2) the filing of a lead/lag study.

The only exception to the above requirement is if the applicant has been previously directed by the Board to undertake a lead/lag study on which its current working capital allowance is based. Under such circumstances, the applicant must either continue to use the results of that study or, in the event it wishes to propose a revision to its allowance, the applicant must file an updated study in support of its proposal. In the absence of such circumstances the two approaches are:

- **13% Allowance Approach**

  The 13% Allowance Approach is calculated to be 13% of the sum of Cost of Power and controllable expenses (i.e., Operations, Maintenance, Billing and Collecting, Community Relations, Administration and General).

The commodity price estimate used to calculate the Cost of Power should be determined in a way that bases the split between RPP and non-RPP customers on actual data and uses the most current RPP price. The calculation should also reflect the most recent Uniform Transmission Rates approved by the Board (EB-2011-0268), issued on December 20, 2011 and effective January 1, 2012. Generally, if new information becomes available for Uniform Transmission Rates and RPP during the course of a proceeding, the Cost of Power would be updated to reflect the new rates.

- **Lead/Lag Study**

  A lead/lag study analysis for two time periods; namely:

  - The time between the date customers receive service and the date that the customers' payments are available to the distributor (the lag); and
  - The time between the date when the distributor receives goods and services from its suppliers and vendors and the date that it pays for them (the lead).

  Leads and lags are measured in days and are generally dollar-weighted. The dollar-weighted net lag (i.e. lag minus lead) days is then divided by 365 (366 in a leap year) and then multiplied by the annual test year cash expenses to determine the amount of working capital required for operations. This amount is included in the distributor's rate base determination.

2.5.1.5 Treatment of Stranded Assets Related to Smart Meter Deployment

The Board's *Guideline: Smart Meter Funding and Cost Recovery* (G-2008-0002) provided two options to distributors regarding the accounting treatment for stranded meters related to the installation of smart meters: (1) leave them in rate base (i.e. Account 1860); or (2) record them in "Sub-account Stranded Meter Costs" of Account 1555.

Since the issuance of this guideline, distributors should have completed their smart meter deployments. Distributors are entitled to receive a rate of return for prudent investments in smart meters while recorded in Account 1555, from the time of their smart meter in-service deployment to the time of the disposition of the smart meters in rates. The earned return on the smart meter investments serves to recognize that the meters are used and useful while they are recorded in Account 1555, although they are not yet included in rate base.

Accounting guidance in the December 2010 Accounting Procedures Handbook FAQs (Q and A #15) provides information as to how the CoS rate-setting process may be used to address the recovery by distributors of costs associated with stranded meters.

On December 15, 2011, the Board issued *Guideline G-2011-0001: Smart Meter Funding and Cost Recovery – Final Disposition*. Section 3.7 and Appendix A-1 provide the most current guidance on the treatment for recovery of costs for stranded meters replaced by smart meters.

Distributors should file as part of their 2013 application a proposed treatment for the recovery of stranded meters that is in conformity with the approach taken by the Board as follows:

1. The total estimated NBV of the stranded meters as of December 31, 2012, or a revised amount calculated in accordance with the above-noted accounting guidance, should be removed from rate base (see Appendix 2-S). The 2013 revenue requirement should not include either a cost of capital return or depreciation expense associated with the total estimated stranded meter costs removed from rate base;
2. The total estimated NBV of the stranded meters should be recovered through separate rate riders for the applicable customer classes. A distributor must outline the manner in which it intends to allocate recovery of the NBV of the stranded meters to the applicable customer rate classes and the rationale for the selected approach;
3. The total estimated stranded meter costs should be tracked in "Sub-account Stranded Meter Costs" of Account 1555; and
4. The associated recoveries from the separate rate riders should also be recorded in this sub-account to reduce the balance in the sub-account.

In order to keep the distributor whole, as noted above, separate rate riders for the applicable customer classes should be proposed to recover the amount of the total estimated stranded costs. If the distributor has not completed or does not expect to complete 100% of its smart meter deployment at the time of the application, there will be a need for the approved stranded meter estimated costs as of December 31, 2012 to be trued-up to actual stranded meter costs when the installation of all smart meters is completed. An adjusting entry should be recorded for this adjustment in the sub-account referenced above. The residual balance (net of recoveries) should be submitted for review as part of the distributor's next CoS application.

Distributors wishing to propose a different approach to that outlined above should provide a full explanation of the proposed approach and justification for it, including why the approach taken in the referenced Decisions would not be applicable to their circumstances.

2.5.2 Capital Expenditures

2.5.2.1 Overview

The applicant must provide an overall summary of capital expenditures over the past five historical years, the bridge year and the test year, showing capital expenditures, treatment of contributed capital and additions and deductions from Construction Work in Progress (“CWIP”). The applicant should group projects appropriately and avoid presentations that result in classification of significant components of the capital budget in the miscellaneous category. Appendix 2-A must be filed.

The following capital expenditure information should be provided by the applicant on a project specific basis:

- For projects over the applicable materiality threshold: need, scope, and purpose of project, related customer attachments, load and capital costs, as well as any applicable cost-benefit analysis;
- Detailed breakdown of starting dates and in-service dates for each project;
- Drivers of capital expenditure increases for the Test year;
- Where a proposed project requires Leave to Construct approval under Section 92 of the OEB Act, with construction commencing in the test year, the applicant must provide a summary of the evidence for that project consistent with the requirements set out in Chapter 4 of these Filing Requirements (sections 4.3 and 4.4 in particular);
- Components of Other Capital Expenditures, including a reconciliation of all capital components to the Total Capital Budget;
- Written explanation of variances, including that of actuals versus the Board-approved amounts for the applicant’s last Board-approved cost of service application;
- Capitalization policy and any proposed changes to that policy; and
- For capital projects that have a project life cycle greater than one year, the proposed accounting treatment, including the treatment of the cost of funds.

2.5.2.2 Capitalization Policy

The applicant must provide its capitalization policy, including changes to that policy since the last rebasing application filed with the Board.

Applicants that must adopt IFRS for financial reporting purposes by January 1, 2013, must adhere to IFRS capitalization accounting requirements for rate making and regulatory reporting purposes after the date of adoption of IFRS.

If the applicant has changed its capitalization policy since the last rebasing application, regardless of whether the applicant has filed the application under MIFRS, USGAAP, or an alternate accounting standard, the applicant must explain the reason for these changes and whether they are a result of adhering to the IFRS capitalization accounting requirements. The changes must be identified, (e.g. capitalization of indirect costs, etc.) and the causes of the changes must also be identified.

2.5.2.3 Capitalization of Overhead

Regardless of whether the applicant has filed the application under MIFRS, USGAAP, or an alternate accounting standard, the applicant must complete Appendix 2-D regarding overhead costs on self-constructed assets.

Burden Rates

The applicant must identify the burden rates related to the capitalization of costs of self-constructed assets. Furthermore, if the burden rates were changed since the last rebasing application, the applicant must identify the burden rates:

- Prior to the change
- After the change

2.5.2.4 Asset Management Plan

- The applicant must provide an asset management plan, if available. .
- If not, an explanation as to why the applicant does not have such a plan must be provided and the applicant must provide information outlining its approach to the planning and prioritization of capital projects. The applicant must also state whether or not it will develop and implement such a plan in the future.
- The applicant must also provide, at a minimum, a three year forecast of capital expenditures (Test year plus two subsequent years).
- The applicant must also state whether or not it has undertaken any asset condition studies and, if so, copies of such studies must be filed.

2.5.2.5 Green Energy Act Plan Capital Expenditures

As discussed in Section 2.3.4, Green Energy Act Requirements, distributors filing cost of service rate applications for 2012 and subsequent rate years must file with the Board a GEA Plan as part of such an application.

Any Capital Expenditures to address Renewable Generation Connection or Smart Grid development per the *Green Energy Act* and the Board's EB-2009-0397 Filing Requirements update of May 17, 2012 should be documented, including a proposal, where applicable, to divide the costs of eligible renewable generation connection investments between the applicant's ratepayers and all Ontario ratepayers per Regulation 330/09, and taking into account the Board's Report on the determination of direct benefits (EB-2009-0349). This Report is discussed in more detail in Section 2.3.4.

A proposal seeking approval for a GEA plan should also clearly identify the period for which the utility is seeking review and approval of any proposed costs, and the utility's proposal for how approved GEA plan costs are to be recovered (e.g., rate adder, rate rider, deferral/variance account).

2.5.2.6 Harmonized Sales Tax ("HST")

The Provincial Sales Tax ("PST") and the Federal Goods and Services Tax were harmonized into the Harmonized Sales Tax ("HST") effective July 1, 2010. As a result of this harmonization, applicants may benefit from an overall net reduction in costs in the form of Input Tax Credits ("ITCs"). This arises due to cost decreases from the receipt of additional ITCs on the purchases of goods and services previously subject to PST that become subject to the HST. These cost decreases may be partially offset by cost increases on certain items that were not previously subject to PST but become subject to the HST with no additional ITCs having been granted (i.e., these items are subject to recaptured ITC requirements).

An applicant must identify whether or not any adjustments have been made to capital expenditures and OM&A to reflect the implementation of the HST and, if so, the applicant must identify in supporting schedules and analyses the respective cost decreases and increases and how these were determined for all categories of costs.

Applicants must describe the steps taken in their budgeting processes to ensure that capital and OM&A costs contained in the application test year exclude all impacts of PST previously embedded in costs for the historical years submitted in evidence. Year-over-year cost comparisons must include a discussion of PST embedded in historical years' costs, and why cost increases for the test year are justifiable.

2.5.3 Service Quality and Reliability Performance

The applicant must provide the following information:

- Reported Electricity Service Quality Requirements ("ESQRs"), as set out in Chapter 7 of the *Distribution System Code*, for the last three historical years. In the event performance is below the established standard, the applicant must provide an explanation for the under-performance, as well as actions taken to address this matter, and any outcomes, as appropriate; and

- SAIDI, SAIFI and CAIDI, for the last three historical years. Reliability performance should be reported for the three indicators for: (1) All interruptions, and (2) All interruptions excluding Loss of Supply (Cause Code 2). In the event performance is outside of the established standard, the applicant must provide an explanation for the under-performance, actions taken to address the issue, and any outcomes (if available). .

Reference documents for service quality and reliability indicators can be found at the following links:

> Service Quality Indicators: Distribution System Code, Chapter 7
> http://www.ontarioenergyboard.ca/OEB/_Documents/Regulatory/Distribution_System_Code.pdf
> Reliability Indicators: Reporting and Record Keeping Requirements dated March 7, 2012 pages 9-12:
> http://www.ontarioenergyboard.ca/OEB/_Documents/Regulatory/RRR_Electricity.pdf

2.6 Exhibit 3. Operating Revenue

This exhibit includes evidence on the applicant's forecast of customers, energy and load, service revenue and other revenue, and variance analyses related to these items.

The applicant must provide its customer, volume and revenue forecast, weather normalization methodology, and other sources of revenue in this exhibit. The applicant must include a detailed description of the methodologies and the assumptions used. The information presented must include:

1) Load and Revenue Forecasts;
2) Variance Analyses; and
3) Other Revenue.

Estimates must be presented excluding commodity revenues.

2.6.1 Load and Revenue Forecasts

2.6.1.1 Overview

The applicant must provide an explanation of the causes, assumptions and adjustments for the volume forecast. All economic assumptions and data sources used in the preparation of the load and customer count forecast should be included in this section (e.g. Housing Outlook & Forecasts, relative energy prices and other variables used in forecasting volumes).

The applicant must also provide an explanation of the weather normalization methodology used. The Board recognizes that an important aspect of any case is the uniqueness of the transmitter or distributor and the circumstances in which it operates. Generic load profiles and universal normalization methods may not reflect the unique customer mix, weather, and economies of each utility's market.

The applicant must include in the test year forecast any impacts arising from the persistence of historical conservation and demand management programs, as well as the forecast impacts arising from new programs deployed in the bridge and test years. This CDM component of the forecast must be specifically identified by class, as the amount approved by the Board will be the basis for the lost revenue adjustment mechanism variance account ("LRAMVA").

Two types of load forecasting models have generally been filed with the Board in previous cost of service applications. These are Multivariate Regression and Normalized Average Use per Customer ("NAC") models. While the applicant is not restricted to filing one of these two models, the following information is required for these two models when used.

2.6.1.2 Multivariate Regression Model

- Rationale as to why the proposed model was chosen;
- Statistics of the regression equation(s) (coefficient estimates and associated t-statistics, and model statistics such as R^2, adjusted R^2, F-statistic, or Root-Mean-Squared-Error, etc.). Explanation for any resulting unintuitive relationships (e.g. negative correlation between load growth and economic growth, load growth and customer growth, etc.). An explanation of modeling approaches and alternative models tested must be provided;
- Explanation of the weather normalization methodology proposed including:
    - If the monthly Heating Degree Days ("HDD") and/or Cooling Degree Days ("CDD") are used to determine normal weather, the monthly HDD and CDD based on a) 10-year average and b) a trend based on 20-years;
    - In addition to the proposed Test year load forecast, the load forecasts based on a) 10-year average and b) 20-year trend HDD and CDD; and
    - Rationale as to why the proposed normal weather methodology was chosen.
- Description of how conservation and demand management ("CDM") impacts have been accounted for in the historical period, and how CDM, including the CDM targets that are a condition of a distributor's licence, is factored into the Test year load forecast; and

- Sources of data used for both the endogenous and exogenous variables. Where a variable has been constructed, complete explanation of the variable, data used and source should be provided.

2.6.1.3 Normalized Average Use per Customer (“NAC”) Model

- Rationale as to why the proposed NAC methodology was chosen;
- Data supporting the calculation of NAC values used in the application for each rate class
- Description of how conservation and demand management (“CDM”) impacts have been accounted for in the historical period, and how CDM, including the CDM targets that are a condition of a distributor’s licence, is factored into the Test year load forecast; and
- Discussion of weather normalization considerations.

2.6.1.4 General Requirements

- Information demonstrating the historical accuracy of the load forecast for at least the past 5 years;
- Schedule of volumes (in kWh and in kW for those rate classes that use this charge determinant), revenues, customer count by rate class and total system load in kWh) for:
  - Historical Actual for the past 5 years;
  - Historical Board Approved;
  - Historical Actual for the past 5 years – weather normalized;
  - Bridge Year;
  - Bridge Year – weather normalized; and
  - Test Year.

2.6.2 Variance Analyses

The applicant must provide the following variance analyses and relevant discussion:

- Historical Board-approved vs. Historical Actual;
- Historical Board-approved vs. Historical Actual – weather normalized;

- Historical Actual – weather-normalized vs. preceding year's Historical Actual – weather-normalized (for the necessary number of years);
- Historical Actual – weather normalized vs. Bridge Year – weather-normalized; and
- Bridge Year – weather-normalized vs. Test Year.

For each rate class, the applicant must provide the following information:

- Weather-normalized (if applicable) average historical actual consumption per customer for historical 5 years and forecasted average consumption for the Bridge Year and Test Year;
- For each rate class, an explanation of the net change in average consumption from last Board Approved and actual for Historical, Bridge Year and Test Year;
- Customer count increases or decreases forecasted for the Test Year with explanations of the forecast by rate class and identification as to whether customer count is shown in year-end or year average format;
- Details for the development of the billing kW value for applicable classes; and
- Revenues, provided on the basis of both existing and proposed rates.

All data used to determine the forecasts should be presented and filed in live MS Excel spreadsheet format.

2.6.3 Other Revenue

The applicant must provide the following information on Other Revenue:

- Breakdown of each of the other distribution revenue accounts (see Appendix 2-F for the required format);
- Comparison of actual revenues for historical years to forecast revenue for Bridge and Test Years, including explanations for significant variances in year-over-year comparisons;
- Any new proposed specific service charges, changes to rates or new rules for applying existing specific service charges; and
- Any revenue from affiliate transactions, shared services or corporate cost allocations as described in section 2.7.5

Revenues or costs (including interest) associated with deferral and variance accounts should not be included in Other Revenue.

2.7 Exhibit 4. Operating Costs

This exhibit must include information that summarizes the Operating, Maintenance and Administrative ("OM&A") Costs and Taxes. The exhibit should include labour and compensation, whether expensed or capitalized, and depreciation expense.

This exhibit should include the following sections:

1. Manager's Summary;
2. Summary and Cost Driver Tables;
3. Variance Analyses;
4. Employee Compensation Breakdown;
5. Shared Services/Corporate Cost Allocation;
6. Purchases of Non-Affiliated Services;
7. Depreciation/Amortization/Depletion;
8. Taxes/PILs;
9. Green Energy Plan OM&A Costs, if applicable; and
10. Conservation and Demand Management ("CDM") Costs, if applicable.

The accounts listed in Appendix 2-G are to be included in the OM&A analyses.

2.7.1 Manager's Summary

The manager's summary should provide a brief explanation (quantitative and qualitative) of the following:

- OM&A Test Year Levels;
- Associated cost drivers and significant changes that have occurred relative to historical and Bridge years;
- Overall trends in costs;
- Inflation rates used for general OM&A and Wages/Benefits. The Board has determined that the GDP-IPI is the most relevant inflation rate for utilities with respect to IRM rate applications, and the applicant should consider this in adopting an inflation rate. If the applicant proposes to use an inflation rate other than the GDP-IPI rate determined by the Board, appropriate justification should be provided (such as studies and/or sources);
- Staffing levels;
- Drivers for changes in salaries and wages and related costs;

- Business environment changes; and
- Materiality thresholds that apply.

2.7.2 Summary and Cost Driver Tables

The applicant must include the following tables as part of its evidence:

- Summary of Recoverable OM&A Expenses (Appendix 2-I);
- Detailed Account by Account OM&A Expenses (Appendix 2-G);
- OM&A Cost Drivers (Appendix 2-J);
- Regulatory Costs (Appendix 2-M); and
- OM&A Cost per Customer and per Full Time Equivalent (Appendix 2-L).

Regardless of whether the applicant has filed the application under MIFRS, USGAAP, or an alternate accounting standard, the applicant must identify the overall level of increase *(or decrease)* in OM&A expense in the test year in relation to a decrease *(or increase)* in capitalized overhead. The applicant must provide a variance analysis for the change in OM&A expense for the test year in respect to each of the bridge year and historical years. The applicant must complete Appendix 2-D.

The applicant must note the specific requirements outlined below:

1. One-time costs;
2. Regulatory costs;
3. Low-income energy assistance programs ("LEAP");
4. Special Purpose Charges related to the Green Energy Act;
5. Charitable donations; and
6. HST Impacts (See Section 2.5.2.6).

2.7.2.1 One-Time Costs

The applicant should identify one-time costs in the historical, bridge and test years and provide an explanation as to how the costs included in the test year are to be recovered.

2.7.2.2 Regulatory Costs

The applicant must provide a breakdown of the actual and anticipated regulatory costs, including OEB cost assessments and expenses for the current application such as legal fees, consultant fees, costs awards, etc. The applicant must provide information supporting the level of the costs associated with the preparation and review of the current application. In addition, the applicant must identify how such costs are to be recovered (i.e., whether the costs are proposed to be amortized and over what period). The amortization period would normally be the duration of the expected cost of service plus IRM term (i.e. four years). If the applicant is proposing a different amortization period, it should explain why it believes this is appropriate.

2.7.2.3 Low-income Energy Assistance Programs ("LEAP")

In March 2009, the Board issued its *Report of the Board: Low Income Energy Assistance Program* (the "LEAP Report") which describes policies and measures for electricity and natural gas distributors to assist low-income energy consumers, including emergency financial assistance.

As set out in the LEAP Report, the Board has determined that the greater of 0.12% of a distributor's Board-approved distribution revenue requirement, or $2,000, is a reasonable commitment by all distributors to emergency financial assistance. The $2,000 minimum is intended to ensure that, for smaller distributors, more funding is available than otherwise would be if based solely on a percentage of distribution revenues. The LEAP amount should be calculated based on total distribution revenues, and is to be recovered from all rate classes based on the respective distribution revenue of each of those rate classes.

A distributor should include the relevant LEAP amount as part of its OM&A expenses. For greater clarity, Board-approved total distribution revenue means a distributor's forecasted service revenue requirement as approved by the Board. If necessary, the LEAP amount proposed would be adjusted to account for any changes resulting from the Board's decision on the final service revenue requirement.

2.7.2.5 Charitable Donations

The applicant must file the amounts paid in charitable donations (per year) from the last Board approved rebasing application until (and including) the Test Year. The recovery of charitable donations will not be allowed for the purpose of setting rates, except for contributions to programs that provide assistance to the distributor's customers in paying their electricity bills and assistance to low income consumers. If the applicant wishes to recover such contributions, it must provide detailed information for those claims.

The applicant must review the amounts filed to ensure that all other non-recoverable contributions are identified, disclosed and removed from the revenue requirement calculation. The applicant should also confirm that no political contributions have been included for recovery.

2.7.3 Variance Analyses

The applicant must provide variance analyses, both quantitative and qualitative, for the comparisons outlined in Appendix 2-H.

2.7.4 Employee Compensation Breakdown

The applicant must complete Appendix 2-K in relation to employee complement, compensation, and benefits. In addition to the information required per Appendix 2-K, the status of pension funding and all assumptions used in the analysis should be provided.

Where there are three or fewer employees in any category, the applicant should aggregate this category with the category to which it is most closely related. This higher level of aggregation should be continued, if required, to ensure that no category contains three or fewer employees.

The applicant must provide details of employee benefit programs, including pensions and other costs charged to OM&A for the last Board-approved rebasing application, Historical, Bridge and Test Years. Post-retirement benefit cost accruals should be identified and described separately from current benefit costs. The most recent actuary report(s) should be included in the pre-filed evidence. What is disclosed in the tax section of the pre-filed evidence should agree with this analysis.

The applicant must provide:

- Explanations and justifications for year-over-year variances (include year and month hired for newly hired employees, inflation rates, collective agreement rates, etc);
- Basis for performance pay, goals, measures, and review processes for any pay-for-performance plans; and
- Any relevant studies conducted by or for the applicant (e.g., compensation benchmarking).

2.7.5 Shared Services and Corporate Cost Allocation

Shared Services is defined as the concentration of a company's resources performing activities (typically spread across the organization) in order to service affiliates (and/or a parent company) with the intention of achieving lower costs and higher service levels.

Corporate Cost Allocation is an allocation of costs for corporate and miscellaneous shared services from the parent company to the utility (and vice versa). This is not to be confused with the allocation of the revenue requirement to rate classes for the purposes of rate design.

The applicant must provide the allocation methodology, a list of costs and allocators, and any 3rd party review of the corporate cost allocation methodology used.

The applicant must complete Appendix 2-N in relation to each service provided or received for the Historical (actuals), Bridge and Test years. The table found in Appendix 2-N must be completed for each year. Additional rows may be added if required.

The table in Appendix 2-N requires the following information:

- *Type of Service Offered:*
  Services such as billing, accounting, payroll, etc. The applicant must identify any costs related to the Board of Directors of the parent company allocated to the applicant.

- *Pricing Methodology:*
  Pricing Methodology includes approaches such as cost-base, market-base, tendering, etc. The applicant must provide evidence demonstrating the pricing methodology used. The applicant should also provide a description of why that pricing methodology was chosen, whether or not it is in conformity with ARC, and why it is appropriate.

- *Price for the Service:*
  The applicant must provide the amount the entity pays for the service that it receives.

- *Cost for the Service:*
  The applicant must provide the cost for the service.

- *% Allocation:*
  The applicant must provide the percentage of the costs allocated to the entity for the service being offered. The Applicant must also provide a description of the allocator and why it is an appropriate allocator.

Variance analyses, with explanations, are required for the following:

- Test Year vs. Last Board-approved Rebasing Application; and
- Test Year vs. Most Current Actuals.

The applicant must identify any Board of Director-related costs for affiliates that are included in its costs.

2.7.6 Purchase of Non-Affiliate Services

Utility expenses incurred through the purchase of services from non-affiliated firms must be documented and justified. An applicant should provide a copy of its procurement policy including information on such areas as the level of signing authority, a description of its competitive tendering process and confirmation that its non-affiliate services purchases are in compliance with it. For any such transactions above the materiality threshold that were procured without a competitive tender, or are not in compliance with the procurement policy, the applicant should provide an explanation as to why this was the case, as well as the following information for Historical (actuals):

- Summary of the nature of the product or service that is the subject of the transaction; and
- A description of the specific methodology used in determining the vendor (including a summary of the tendering process/cost approach, etc.).

2.7.7 Depreciation/Amortization/Depletion

The information outlined below is required for Depreciation/Amortization/Depletion:

- The applicant must provide details for Depreciation, Amortization and Depletion by asset group for the Historical, Bridge and Test Years, including asset amount and rate of depreciation or amortization. This should tie back to the accumulated depreciation balances in the continuity schedule under Rate Base.
- The applicant must identify any Asset Retirement Obligations ("AROs") and any associated depreciation or accretion expenses in relation to the AROs, including the basis and calculation of how these amounts were derived.
- In particular, the Board's general policy for electricity distribution rate setting is that capital additions would normally attract six months of depreciation expense when they enter service in the test year. This is commonly referred to as the "half-year" rule. The applicant must identify its historical practice and its proposal for the test year. Variances from this "half-year" rule, such as calculating depreciation based on the month that an asset enters service, must be documented with supporting rationale.

- The applicant must provide a copy of its depreciation/amortization policy, if available. If not, the applicant should provide a written description of the depreciation practices followed and used in preparing the application. Regardless of the accounting standard used in the application, the applicant must provide a summary of changes to its depreciation/amortization policy made since the applicant's last cost of service filing.
- The applicant must ensure that the significant parts or components of each item of PP&E are being depreciated separately. The applicant must explain if it departs from this practice.
- For an applicant that files a 2013 cost of service application on the basis of MIFRS or adheres to IFRS requirements with respect to depreciation and capitalization:
    - The applicant must use the Board sponsored Kinectrics study or provide its own study to justify changes in useful lives.
    - The applicant must provide a list detailing all asset service lives. The applicant must detail differences of its asset service lives from the Typical Useful Lives (TUL) from the Kinectrics Report and provide a detailed explanation for using a service life that is different from the TUL in the Kinectrics Report.
    - Applicants must perform a recalculation to determine the average remaining life of the opening balance of assets on the transition date to IFRS (i.e. excluding the transition year capital additions).
    - If an applicant chooses to adopt IFRS for financing reporting in 2012, the applicant must complete Appendix 2-CA to Appendix 2-CD (inclusive).
    - If an applicant chooses to adopt IFRS for financial reporting in 2013, the applicant must complete Appendix 2-CE to Appendix 2-CH (inclusive).

If the applicant has adopted an accounting standard other than IFRS, the applicant must specify the details if it adopted, in part or in full, TUL estimates that were used in the Board sponsored Kinectrics study or its own asset service life studies and determine the impacts. The applicant must provide a detailed justification for any changes in service lives. Applicants that filed a rate application under an alternate accounting standard other than IFRS must complete Appendix 2-CI.

2.7.8 Taxes or Payments In Lieu of Taxes ("PILs") and Property Taxes

The applicant must provide the information outlined below:

- Detailed calculations of PILs (including a completed version of the PILs model available on the Board's web site), or Provincial and Federal taxes, as applicable, including derivation of adjustments (e.g., Tax credits, CCA adjustments) for the Historical, Bridge and Test Years. Note: Regulatory assets (and regulatory liabilities) should generally be excluded from PILs calculations both when they were created, and when they were collected, regardless of the actual tax treatment accorded those amounts.

- Supporting schedules and calculations identifying reconciling items;
- Copies of most recent Federal and Provincial tax returns (non-utility tax items, if material, should be separated);
- Financial statements included with tax returns, if different from the financial statements filed in support of the application (section 2.4.3).
- The federal and Ontario Notice of Assessments, Notice of Re-assessments (if applicable), Statements of Adjustments, and any other correspondence with the CRA and Ontario Ministry of Finance regarding any tax items, or tax filing positions that may be in dispute, or under consideration or review, for the three immediately prior tax years.
- A calculation of tax credits (e.g., Apprenticeship Training Tax Credits, education tax credits). SRED return, if filed, may have confidential personal information of the people who are apprenticing like SIN, address, hourly rate, etc. which should be excluded from the filing; and
- Supporting schedules, calculations and explanations for “other additions” and “other deductions” in the applicant’s PILs model.

2.7.8.1 Non-recoverable and Disallowed Expenses

There may be some distribution-only expenses incurred by a distributor that are deductible for general tax purposes, but for which recovery in 2013 distribution rates is partially or fully disallowed.

Where an expense incurred by a distributor is non-recoverable in the revenue requirement (e.g. certain charitable donations) or disallowed for regulatory purposes, such amounts will also be excluded from the regulatory tax calculation.

2.7.8.2 Integrity Checks

The applicant must ensure the following integrity checks have been achieved in its application:

- The depreciation and amortization added back in the application’s PILs model agree with the numbers disclosed in the rate base section of the application.
- The capital additions and deductions in the UCC/ CCA Schedule 8 agree with the rate base section for historic, bridge and test years.
- Schedule 8 of the most recent federal T2 tax return filed with the application has a closing December 31st historic year UCC that agrees with the opening bridge

year UCC at January 1st. If the amounts do not agree, then the applicant must provide a reconciliation with explanations for the reasons.

- The CCA deductions in the application's PILs tax model for historic, bridge and test years agree with the numbers in the UCC schedules for the same years filed in the application.
- Loss carry-forwards, if any, from the tax returns (Schedule 4) agree with those disclosed in the application.
- CCA is maximized even if there are tax loss carry-forwards.
- A statement is included in the application as to when the losses, if any, will be fully utilized.
- Accounting OPEB and pension amounts added back on Schedule 1 reconciliation of accounting income to net income for tax purposes, must agree with the OM&A analysis for compensation. The amounts deducted must be reasonable when compared with the notes in the audited financial statements, FSCO reports, and the actuarial valuations; and
- The income tax rate used to calculate the tax expense must be consistent with the utility's actual tax facts and evidence filed in the proceeding.

2.7.9 *Green Energy Act* Plan O&M Costs

As discussed in Section 2.3.3, Green Energy Act Requirements, distributors filing cost of service rate applications for 2012 and subsequent rate years must file with the Board a GEA Plan as part of such an application.

Any Operations and Maintenance costs to address Renewable Generation Connection or Smart Grid development as per the Green Energy Act and the Board's EB-2009-0397 Filing Requirements as updated on May 17, 2012, should be outlined, including a proposal, where applicable, to divide the costs of eligible renewable generation connection investments between the applicant's ratepayers and all Ontario ratepayers as per Regulation 330/09 and taking into account the Board's Report on the determination of direct benefits (EB-2009-0349). This Report is discussed in more detail in Section 2.3.3.

A proposal seeking approval for a GEA plan should also clearly identify the period for which the utility is seeking prudence review and approval, and the utility's proposal for how approved GEA plan costs are to be recovered (e.g., rate adder, rate rider, deferral/variance account).

2.7.10 Conservation and Demand Management ("CDM") Costs

The CDM Code was issued on September 16, 2010 and sets out obligations and requirements in relation to CDM activities after December 31, 2010. The CDM Code applies to CDM Programs that start on January 1, 2011 and end on December 31, 2014 or occur anytime in between those two dates. All electricity savings (kWh) and peak demand savings (kW) resulting from CDM Programs must also occur within that timeframe to be counted against a distributor's CDM Targets.

The Board expects that, going forward, most CDM funding for distributors for the 2012-2014 period, will be provided by the Ontario Power Authority ("OPA"). It is expected that a distributor will enter into contracts to deliver OPA-Contracted Province-Wide CDM Programs. If a distributor seeks to deliver programs not being offered through the OPA-Contracted Province-Wide Programs, it is able to apply for Board approval for programs that are in compliance with the rules set out in the Board's CDM Code and clarified in the April 26, 2012 Conservation and Demand Management Guidelines (EB-2012-0003) (CDM Guidelines). This will be funded through the global adjustment mechanism, and therefore should not be included in distribution rates.

Lost Revenue Adjustment Mechanism

The lost revenue adjustment mechanism ("LRAM") is a retrospective adjustment, which is designed to account for differences between the forecast revenue loss embedded in rates and the actual revenue loss.

On April 26, 2012, the Board issued updated CDM Guidelines. The CDM Guidelines were developed to provide more clarity on the CDM Code and what information needs to be filed in support of Board-Approved CDM program applications, as well as to provide updated details on the LRAM and the associated variance account for the 2011-2014 term.

LRAM Variance Account ("LRAMVA") for 2011 – 2014

For CDM programs delivered within the 2011 to 2014 term, the Board established Account 1568 as the LRAMVA to capture the variance between the Board-approved CDM forecast and the actual results at the customer rate class level. Accounting guidelines regarding the LRAMVA can be found in Appendix B of the 2012 CDM Guidelines. Distributors should refer to the CDM Guidelines for further details.

The distributor shall compare the Board-approved forecasted CDM related load forecast reduction to the actual CDM results. The variance calculated from this comparison shall be recorded in separate sub-accounts for the applicable customer rate classes.

Disposition of the LRAMVA

At a minimum, distributors must apply for the disposition of the balance in the LRAMVA as part of their COS applications. Distributors may apply for the disposition of the balance in the LRAMVA on an annual basis, as part of their IRM rate applications, if the balance is deemed significant by the applicant.

In support of its application for lost revenues distributors must file the following:

- A statement indicating that the distributor has used the most recent input assumptions available at the time of the program evaluation when calculating its LRAM amount;
- A statement indicating that the distributor has relied on the most recent and appropriate final evaluation report from the OPA in support of its LRAM calculation;
- Separate tables for each rate class that shows the LRAM amounts requested by the year they are associated with and the year the lost revenues took place;
- LRAM calculations, determined by calculating the energy savings by customer class and valuing those energy savings using the distributor's Board-approved variable distribution charge appropriate to the class;
- A statement, and if applicable a table, that indicates if carrying charges are being requested on the LRAM amount;
- For Board-approved programs, a third party report, in accordance with the OPA's EM&V Protocols as set out in Section 6.1 of the CDM Code, that provides a review and verification of the LRAM calculations, including:
    - Confirmation of the use of correct input assumptions and LRAM calculations
    - Verified participation amounts
    - The net and gross kW and kWh impacts of each program and for each class, both gross and net of free riders, separated by year
    - Verification of any carrying charges requested; and
- For OPA Contracted Province-Wide Programs the distributor must provide documentation (i.e. final evaluation report from the OPA) of the distributor's results.

A separate third party review of the distributors OPA-Contracted Province-Wide CDM programs is not required.

LRAM and/or SSM for pre-2011 CDM activities

In Section 3.4.2 of Chapter 3 of the Filing Requirements, issued June 22, 2011, the Board stated that if a distributor does not file for the recovery of LRAM or SSM amounts in its 2012 rate application, it will forego the opportunity to recover LRAM or SSM for the legacy period of CDM activity (2005 – 2010).

The Board expects LRAM claims for pre-2011 CDM activities to have been completed with the 2012 rate applications, outside of persisting historical CDM impacts realized after 2010 for those distributors whose load forecast has not been updated as part of a cost of service application. SSM is not applicable for savings persisting from the legacy period.

In support of its application for persisting lost revenues from pre-2011 CDM programs, distributors must file the following:

- A statement confirming that the distributor's load forecast has not been updated as part of a cost of service application since the CDM programs, for which persistent lost revenue is sought, were implemented;
- A statement indicating that the distributor has used the most recent input assumptions available at the time of the program evaluation when calculating its LRAM amount;
- A statement indicating that the distributor has relied on the most recent and appropriate final evaluation report from the OPA in support of its LRAM calculation;
- Separate tables for each rate class that shows the LRAM amounts requested by the year they are associated with and the year the lost revenues took place;
- LRAM calculations, determined by calculating the energy savings by customer class and valuing those energy savings using the distributor's Board-approved variable distribution charge appropriate to the class;
- A statement, and if applicable a table, that indicates if carrying charges are being requested on the LRAM amount;
- A third party report that provides a review and verification of the LRAM calculations, including:
    - Confirmation of the use of correct input assumptions and LRAM calculation
    - Verified participation amounts
    - The net and gross kW and kWh impacts of each program and for each class, both gross and net of free riders, separated by year
    - Verification of any carrying charges requested.

2.8 Exhibit 5. Cost of Capital and Capital Structure

The Board's general guidelines for cost of capital in rate regulation are currently provided in the *Report of the Board on Cost of Capital for Ontario's Regulated Utilities* (the "2009 Report"), issued December 11, 2009. This report supersedes the previous *Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors* (the "2006 Report") of December 20, 2006.

The 2009 Report states that cost of capital parameters will be based on data three full months prior to the effective date for new rates. The Board issues cost of capital parameter updates for cost of service applications for rates effective May 1 of the test year on an annual basis, normally around the beginning of March for use in that year's cost of service applications. The most recent data should be used as the default values in the 2012 rate applications, subject to an update when new parameters are available prior to the issuance of the Board's Decision for a specific distributor's application. For cost of service applications requesting a January 1 effective date, the Board will issue cost of capital parameters based on data for September of the previous year, in October or November.

If the applicant wishes to adopt the Board's guidelines for the cost of capital, the application should clearly state this and confirm that the cost of capital parameters will be updated in accordance with the Board's guidelines at the time of the Board's decision.

Alternatively, the applicant may apply for a utility-specific cost of capital and/or capital structure. If the applicant wishes to take such an approach, it must provide appropriate justification and supporting evidence for its proposal.

2.8.1 Capital Structure

The elements of the deemed capital structure are shown below and must be presented with the required schedules (Appendices 2-OA and 2-OB) for current Board approved, Historical Actuals, Bridge and Test Years:

- Long-Term Debt;
- Short-Term Debt;
- Preference Shares; and
- Common Equity.

Appendix 2-OB must be completed for the required years of all historical years, Bridge Year and Test Year.

Any explanations of changes in actual capital structure are required including:

- Retirements of debt or preference shares and buy-back of common shares; and
- Short-Term Debt, Long-Term Debt, preference shares and common share offerings.

2.8.2 Cost of Capital (Return on Equity and Cost of Debt)

These requirements are outlined in the 2009 Report. The applicant must provide the following information for each year:

- Calculation of the cost for each capital component;
- Profit or loss on redemption of debt and/or preference shares, if applicable;
- Copies of any current promissory notes or other debt arrangements with affiliates;
- Explanation of the applicable debt rate for each existing debt instrument, including an explanation on how the debt rate was determined and is in compliance with the policies documented in the 2009 Report;
- Forecasts of new debt anticipated in the bridge and test years, including estimates of the applicable rate and any pertinent information on each new debt instrument (e.g. whether the debt is affiliated or with a third party, expected term/maturity, any capital project(s) that the debt funding is for, etc.); and
- If the applicant is proposing any rate that is different from the Board guidelines, a justification of forecast costs by item, including key assumptions.

2.8.3 Not-for-Profit Corporations

In prior decisions, the Board has determined that applicants which are not-for-profit corporations may apply using the Board's deemed capital structure, cost of capital and working capital allowance to the extent that the excess revenue is to be used for the purpose of meeting the applicant's need to build up or accumulate appropriate operating and capital reserves. The Board has further stated that once the appropriate limits for these reserves have been achieved, it would expect such applicants to submit an application seeking a rate adjustment.

2.9 Exhibit 6. Calculation of Revenue Deficiency or Sufficiency

The applicant must include the following information in this exhibit, excluding energy (i.e. cost of power and associated costs) costs and revenues:

- Determination of Net Utility Income;
- Statement of Rate Base;

- Actual Utility Return on Rate Base;
- Indicated Rate of Return;
- Requested Rate of Return;
- Deficiency or Sufficiency in Revenue; and
- Gross Deficiency or Sufficiency in Revenue.

The filing requirements have been designed in a manner to isolate the delivery-related deficiency/sufficiency separate and apart from the energy-related deficiency/sufficiency. In keeping with this separation, the applicant must provide revenue deficiency or sufficiency calculations net of electricity price differentials captured in the RSVAs and also net of any cost associated with LV charges or smart meter expenditures/revenues being tracked through variance accounts and for which disposition is not being sought in the application.

The applicant must provide a summary of the drivers of the test year deficiency/ sufficiency, along with how much each driver contributes. Specific references to the data contained in the detailed schedules and tables should be provided so that parties can map the summary cost driver information to the evidence supporting it.

The impacts of any change in methodologies should be provided on the overall deficiency/sufficiency and on the individual cost drivers contributing to it.

The revenue requirement components in the application and the resulting revenue deficiency/sufficiency in this Exhibit should correspond with the calculations in the Revenue Requirement Work Form.

2.10 Exhibit 7. Cost Allocation

The following areas are discussed in this section:

1. Cost Allocation Study Requirements;
2. Revenue-to-Cost ratios; and
3. Class Revenues and Revenue-to-Cost Ratios

2.10.1 Cost Allocation Study Requirements

The Board expects that filings made by a distributor will follow the cost allocation policies outlined in the Board's report of March 31, 2011 *Review of Electricity Distribution Cost Allocation Policy* (EB-2010-0219).

A completed cost allocation study using the Board approved methodology must be filed. This filing must reflect future loads and costs and be supported by appropriate explanations and live Excel spreadsheets. The 2011 update of the model issued by the Board will be available on the Board's web site.

If updated load profiles are not available, the load profiles of the classes may be the same as those provided by Hydro One for use in the Informational Filing, scaled to match the load forecast as it relates to the respective rate classes (see section 2.6.2 above). In particular, if a rate class has experienced a decline in customers or disappeared, or will disappear in the Test Year, the model must be consistent with the updated load forecast, and include an explanation of the changed load forecast of the rate class.

Distributors should refer to section 2.6.4 of the March 31, 2011 report concerning weighting factors for allocation of certain costs. A description of the weighting factors is required, including an explanation of why the distributor has chosen to use the default placeholders if applicable.

If using the Board approved model, the distributor should file a hard copy of input sheets I-6 and I-8, and output sheets O-1 and O-2 (first page only). Input sheet I.2, cells c-17 and d-17 should be used to identify the final run of the model on each sheet. If using another model, the distributor should file equivalent information. A complete hard copy of the cost allocation model is not required, but the distributor must file a complete Excel model electronically with the application.

Distributors should note the following:

- Large General Service and Large Use classes: The treatment of the Transformer Ownership Allowance has been revised in the updated version.

- Streetlighting: Experience has shown that the revenue requirement of the Streetlighting class is sensitive to inputs related to the number of connections (which determines the number of services) as distinct from the number of streetlighting fixtures (which determines the estimated coincident and non-coincident loads). Distributors are encouraged to use information that is as accurate as possible, and to stay apprised of progress in modeling in this area.

- Embedded Distributor Class: Any distributor that is the host to one or more distributors must provide information on the cost of serving those embedded distributors in one of two ways. If the host has a separate rate class for embedded distributor(s) or is proposing such a class, the host distributor must include the class as such in its cost allocation study and in Appendix 2-P. If the host distributor proposes to bill the embedded distributor(s) as if it/they were General Class customers, the costs and revenue should be included with that class in the cost allocation study and Appendix 2-P and the host distributor must also complete Appendix 2-Q which shows details on how much of the host's facilities are required to serve the embedded distributor(s).

- microFIT class: The Board does not expect a distributor to include microFIT as a separate class in the cost allocation model in 2013, because it is not expected to have a material effect on outcomes. The cost allocation model will allocate costs and revenues without requiring data inputs from the distributor, and will also produce a calculation of unit costs to be used to update the uniform rate at a future date.
- New Customer Class: If the distributor is establishing a new customer class, the rationale for doing so is required, and information provided in the applicant's previous cost-of-service application concerning class revenue requirements should be restated in Appendix 2-P on the basis of the proposed customer classes to provide continuity with the proposed new customer class(es).

2.10.2 Class Revenue Requirements and Class Revenues

Appendix 2-P shows the format for filing cost allocation information and includes four tables.

The first table in Appendix 2-P is a format for showing the test year class revenue requirements, which is produced in output sheet O-1 of the Board model. This table also includes a comparison to the most recent study previously filed with the Board.

The Board has established ranges for revenue-to-cost ratios. Rate re-balancing is the process of changing rates by different percentage amounts for different customer rate classes. To support a proposal to re-balance rates, the distributor must provide information on the revenue by class that would pertain if all rates were changed by a uniform percentage. These ratios must be compared with the ratios that will result from the rates being proposed by the distributor.

The second table in Appendix 2-P shows three revenue scenarios, by rate class. Each scenario is based on the forecast of class billing quantities. The scenarios are, respectively, the forecast quantities multiplied by: a) existing rates, b) prorated existing rates that would yield the test year Base Revenue Requirement, and c) proposed class revenues. The table also shows the allocation of Miscellaneous Revenue to the rate classes, which is an output from the cost allocation model.

2.10.3 Revenue-to-Cost Ratios

The Board has established its policy with respect to how closely class revenues should be related to allocated costs. The policy is expressed in terms of revenue-to-cost ratios. The Board has updated the range of acceptable ratios in its March 31, 2011 Report, section 2.9.4. Rate re-balancing is the process of changing rates by different percentage amounts for different customer rate classes. The distributor should propose re-balancing to bring the revenue-to-cost ratio for one or more classes into the Board's policy range.

The third table in Appendix 2-P combines information from the previous two tables in the form of Revenue–to-Cost Ratios and includes the following information for each class:

- The previously approved ratios most recently implemented by the distributor;
- The ratios that would result from the most recent approved distribution rates and the distributor's forecast of billing quantities in the test year, prorated upwards or downwards (as applicable) to match the revenue requirement, expressed as a ratio with the class revenue requirements derived in the updated cost allocation model; and
- The ratios that are proposed for the Test Year, which are the proposed class revenues, together with the updated cost allocation model.

If the distributor proposes to continue re-balancing after the Test Year, the ratios proposed for the subsequent year(s) should be provided. The fourth table in Appendix 2-P provides a format for presentation. In particular, if the proposed ratios are outside the Board's policy range in the Test year, the distributor must show the proposed ratios in subsequent years that would move the ratios into the policy range.

If using a cost allocation model other than the Board model, the distributor must ensure that costs exclude LV costs, and Smart Meter costs being recording in accounts 1555 and 1556, and that revenues exclude rate riders and rate adders. The distributor should also ensure that information relevant to microFIT unit costs and revenue is consistent with the output from the Board's model.

2.11 Exhibit 8. Rate Design

The following areas are discussed in this section:

1. Fixed/Variable Proportion
2. Retail Transmission Service Rates ("RTSRs")
3. Retail Service Charges
4. Wholesale Market Service Charges
5. Specific Service Charges
6. Low Voltage Charges (where applicable)
7. Loss Adjustment Factors
8. Rate Schedules

9. Bill Impact Information
10. Mitigation Procedures (where applicable)

Please note that monthly fixed charges should be shown to two decimal places while variable charges should be shown to four places. Distributors wishing to depart from this approach should provide a full explanation as to why they believe it is necessary**.**

2.11.1 Fixed/Variable Proportion

The applicant must provide the following information related to the fixed/variable proportion of its proposed rates:

- Current fixed/variable proportion for each rate class, along with supporting information;
- Proposed fixed/variable proportion for each rate class, including an explanation for any changes from current proportions; and
- A table comparing current and proposed monthly fixed charges with the floor and ceiling as calculated in the cost allocation study. The applicant must include an explanation if the monthly fixed charge for any customer class exceeds the ceiling.

The fixed/variable analysis should be net of (i.e., exclude) rate adders, funding adders and rate riders (i.e., Low Voltage, smart meters, GEA, deferral/variance account disposition, etc).

2.11.2 Retail Transmission Service Rates ("RTSRs")

In preparing its application, the distributor should reference the Board's *Guideline G-2008-0001: Electricity Distribution Retail Transmission Service Rates,* October 22, 2008, and subsequent updates to the Uniform Transmission Rates ("UTRs"). A filing module will be provided to distributors to assist in calculating the distributor's class-specific RTSRs.

The distributor should ensure that the information provided in this section is consistent with that provided in the working capital allowance calculation provided in Section 2.5.1.4, as it relates to rates such as RTSRs, or provide explanations for any differences.

2.11.3 Retail Service Charges

Retail services refer to services provided by a distributor to retailers or customers related to the supply of competitive electricity as set out in the Retail Settlement Code ("RSC"). Distributors should note that the current retail service rates and charges were established on a generic basis. The Board expects applicants proposing changes to the level of the rates and charges or the introduction of new rates and charges, to provide evidence that they have consulted with retailers about the changes and have provided them with adequate notice of such changes.

Distributors should maintain the appropriate Retail Service Costs Variance Accounts ("RCVA") to record the difference between charges rendered to customers and retailers, and the direct incremental costs for the provision of these services.

2.11.4 Wholesale Market Service Rate

The Wholesale Market Service Rate is designed to allow distributors to recover costs charged by the Independent Electricity System Operator ("IESO") for the operation of the IESO administered markets and the operation of the IESO-controlled grid.

The Wholesale Market Service Rate is an energy based rate (per kWh). This rate only applies to those customers of a distributor who are not wholesale market participants. An embedded distributor who is not a wholesale market participant would be treated as a customer to the host distributor and charged the same rate.

The Board has determined that this rate should be consistent across LDCs and, as such, changes to this rate would normally be made on a generic basis. Distributors wishing to apply for a change in this rate, outside of any changes that may be made to the generic rate, should provide justification as to why their specific circumstances would warrant such a change.

2.11.5 Specific Service Charges

The distributor should describe the purpose of each specific service charge for which it is seeking approval, unless the charge is one prescribed by the *Distribution System Code,* and ensure that this corresponds with the evidence under Operating Revenues (see section 2.6.3).

If the distributor is requesting either a new specific service charge or a change to the level of an existing charge, it should describe the purpose of the charge and provide calculations supporting the determination of the charge including the following elements:

- Direct labour (internal and/or external);
- Labour rate (internal and/or external);

- Burden rate;
- Incidental (e.g. postage for mail); and
- Vehicle time and rate (if applicable).

2.11.6 Low Voltage Service Rates (where applicable)

If the distributor is embedded (see section 2.4.1) the distributor must provide the following information:

- Forecast of LV cost, which is the sum of the host distributor's charges to the applicant.
- Support for the forecast of LV costs: forecast volumes and actual or forecast host distributor's LV rates. For example, a distributor whose host distributor is Hydro One would list ST lines, plus an ST Service Charge, plus any other charges such as facility charges for connection to a shared distribution station that apply to the embedded applicant's monthly bill from the host distributor, together with the applicable charge determinants.
- Allocation of forecast LV cost to customer classes (generally in proportion to Transmission Connection Rate revenues); and
- Proposed LV rates by customer class to reflect these costs.

2.11.7 Loss Adjustment Factors

The distributor must identify the proposed Supply Facilities Loss Factor ("SFLF"), distribution and total loss factors for the Test year.

The distributor must file the following information related to its proposed loss factors:

- A statement as to whether the applicant is embedded;
- Details of loss studies and recommendations, if required by a previous decision;
- Calculations showing the losses in previous years. Five years of historical data is preferred. A minimum filing of three years of data is required;
- Appendix 2-R showing the energy delivered to the distributor with and without losses;
- Explanation of distribution losses greater than 5%;
- Details of actions currently planned, and actions taken to reduce losses in previous five years and results if proposed distribution loss factor is greater than 5%; and

- Explanation of the derivation of the SFLF, including reasons for any differences from the standard SFLFs referenced in Appendix 2-R, Section H.

2.11.8 Revenue Reconciliation

The applicant must provide the current and proposed tariff of rates and charges. For the proposed tariff of rates and charges, the following information should be provided:

- Detailed calculations of revenue per rate class under current rates and proposed rates by customer class; and
- Detailed reconciliation of rate class revenue and other revenue to total revenue requirement (i.e., breakout volumes, rates and revenues by rate component, etc).

The applicant must provide an explanation of proposed changes to terms and conditions of service and the rationale behind those changes if the changes affect the application of the rates. The applicant should note that only rates shown on the Board-approved Tariff of Rates and Charges can be applied.

The applicant must provide a completed Appendix 2-V.

2.11.9 Bill Impacts

Appendix 2-W must be filed for all classes. This appendix identifies existing rate schedules, the revenue deficiency recovery, a summary of proposed changes to rates, proposed volume and revenue recovery, and detailed bill impacts (including % change in distribution, % change in distribution excluding pass-through costs, % change in delivery and % change in total bill).

The distributor should provide the impact of changes resulting from the as-filed application on representative samples of end-users, i.e., volume, percentage rate change and revenue. The distributor should include the base distribution rates, any applicable rate adders or rate riders, and RTSRs. Commodity rates and regulatory charges should be held constant.

The bill comparisons should be provided for typical customers and consumption levels. Bill impacts must be provided for residential customers consuming 800 kWh per month and general service customers consuming 2,000 kWh per month and having a monthly demand of less than 50 kW. The applicant should also provide similar typical impacts for other classes, as well as any other comparisons the applicant may wish to provide for the residential and general service less than 50 kW classes. For certain classes where one or more customers have unique consumption and demand patterns and which may be significantly impacted, the applicant should show a typical comparison, and provide an explanation.

2.11.10 Mitigation Procedures (as applicable)

2.11.10.1 Mitigation Plan Approaches

The applicant must file a mitigation plan if total bill increases for any customer class exceed 10%. The mitigation plan should include the following information:

1. A specification of all customer classes or groups of customers that were initially identified as having increases in excess of 10% and the magnitude of these increases.

2. Any mitigation measures undertaken, e.g. reductions to the revenue requirement, inter- or intra-class shifts, and the resulting impacts.

3. A justification for all mitigation measures proposed.

4. A detailed description of all mitigation adjustments made.

5. Revised impact calculations.

6. Any other information the applicant believes is relevant.

The applicant should include the following bill comparisons based upon the proposed and the existing rates (including any Board-approved rate riders or adders):

- “Total” bill (including a commodity component and other rates);
- “Delivery charge” component of the customer’s bill (i.e. excluding the commodity component); and
- “Distribution charge” component of the customer’s bill (i.e. excluding the commodity component and other non-distribution rates).

The bill comparisons should be provided for typical customers and consumption levels (e.g., residential customers consuming 800 kWh per month, general service customers consuming 2,000 kWh per month and having a monthly demand of less than 50 kW, etc). Where the consumption patterns of a utility’s typical customers vary markedly from these norms, the applicant should explain the customer profile(s) that it wishes to use, as an additional calculation.

The bill comparisons should assume a constant commodity price and other rates, despite potential changes such as changes in the commodity price and other rates may not be known at the time of an application.

If a distributor determines in the course of the development of its mitigation plan that there is no suitable manner in which to resolve the bill increases exceeding the mitigation threshold, such a finding must be stipulated in the mitigation plan and supported with sufficient evidence.

The Board stated in its *2006 Electricity Distribution Rate Handbook Report of the Board* (RP-2004-0188), May 11, 2005 that, as a general rule, it did not favour mitigation plans dependent on imposing otherwise unwarranted increases on one customer class in order to reduce increases for another. The Board added that adjustments within a class of customers would be much more acceptable, such as changes to the fixed/variable splits which may have the effect of reducing bill impacts.

The Board also stated that mitigation plans that are predicated on reductions in the revenue requirement are problematic as revenue requirement reductions should incur to the benefit of all the distributor's customers and form part of the basic rate application, not be a response to hardship cases. The Board expressed its concern that a distributor should not compromise its overall ability to deliver reliable service in order to address discrete instances of hardship.

The Board further stated that a distributor may choose to reduce its regulated rate of return in order to address situations requiring mitigation plans. However, the Board added that such a course of action should be prudently considered in light of the medium and long-term financial health of the organization and its ability to provide reliable service.

Mitigation policy is currently under review as one of the three policy initiatives which are part of the Board's consultation on development of a renewed regulatory framework for electricity (EB-2010-0378). In that light, there may be changes to the Board's mitigation policies going forward.

2.11.10.2 Rate Harmonization Mitigation Issues

Distributors which have merged or amalgamated service areas, and which have not yet fully harmonized the rates between or among the affected distribution service areas, may file a rate harmonization plan. The plan must include a detailed explanation and justification for the implementation plan, and an impact analysis.

In the event that the combined impact of the cost of service based rate increases and harmonization effects result in total bill increases for any customer class exceeding 10%, the distributor should include a discussion of proposed measures to mitigate any such increases in its mitigation plan or provide a justification as to why a plan is not required.

A migration to fully harmonized rates that is to be accomplished over more than one year should be supported by a detailed plan for accomplishing this during the IRM period.

2.12 Exhibit 9. Deferral and Variance Accounts

The information outlined below is required regardless of whether or not the applicant is seeking disposition of any or all deferral and variance accounts:

- List of all outstanding deferral and variance accounts and sub-accounts. The applicant must provide a brief description of any account that the applicant may have used differently than as described in the APH;
- The continuity schedule for the period following the last disposition to the present, showing separate itemization of opening balances, annual adjustments, transactions, interest and closing balances. Where appropriate, information should be shown separately by each sub-account (e.g. Account 1588: RSVA – Power, sub-account Global Adjustment, which is only applicable to non-RPP customers for recovery or refund), must be shown separately. A completed version of the continuity schedule available on the Board's web site must be filed in working Microsoft Excel format;
- Interest rates applied to calculate the carrying charges for each regulatory deferral and variance account. The applicant must provide the rates by month or by quarter for each year;
- Explanation if the continuity schedule differs from the trial balance reported through the Electricity Reporting and Record-keeping Requirements and the Audited Financial Statements.
- Identification of which of the above accounts the applicant will continue on a going forward basis; and
- Statement as to any new accounts or sub-accounts that the applicant is requesting, and justification for each requested account or sub-account. This should correspond with information provided in Exhibit 1 (see section 2.4.1).
- A statement as to whether the applicant has made any adjustments to deferral and variance account balances that were previously approved by the Board on a final basis in both cost of service and IRM proceedings (i.e. balances that were adjusted subsequent to the balance sheet date that were cleared in the most recent rates proceeding). If this is the case, the applicant must provide explanations for the nature and amounts of the adjustments and include supporting documentation.
- A breakdown of energy sales and cost of power expense, as reported in the audited financial statements, by USoA account number. The applicant must tie these numbers to the audited financial statements. If there is a difference between the energy sales and cost of power expense reported numbers, the applicant must explain why it is making a profit or loss on the commodity.

- A statement confirming that the applicant pro-rates the IESO Global Adjustment Charge into the RPP and non-RPP portions. If this is not the case, the applicant must provide an explanation.

2.12.1 PILs and Tax Variances for 2006 and Subsequent Years - Account 1592

Beginning in 2011, the Board began disposing of account 1592, PILs and Tax Variances for 2006 and Subsequent Years, on a final basis. The Board expects distributors to file for disposition of account 1592 in their cost of service applications. Distributors should complete and file Appendix 2-T in support of their request to dispose of account 1592.

2.12.2 Harmonized Sales Tax ("HST") Deferral Account

During the 2010 IRM application process, the Board directed electricity distributors to record in deferral account 1592 (PILs and Tax Variances, Sub-account HST/OVAT Input Tax Credits ("ITCs")), beginning July 1, 2010, the incremental ITCs received on distribution revenue requirement items that were previously subject to PST and became subject to HST.

In December 2010, as part of its Frequently Asked Questions on the Accounting Procedures Handbook for electricity distributors, the Board provided accounting guidance on this matter and provided a simplified approach designed to facilitate administrative cost-saving opportunities. Applicants filing for disposition of this sub-account in their cost of service applications should review this material.

No more amounts should be recorded in Account 1592 (PILs and Tax Variances, Sub-account HST/OVAT ITCs for the Test Year and going forward, as the impact of the HST and associated ITCs on capital and operating costs in the Test Year should be reflected in the applied-for revenue requirement (see section 2.5.2.4). For the 2013 Test Year for example, entries to record variances in the sub-account of Account 1592 would cover the period from July 1, 2010 to December 31, 2012 since the Test Year, which starts January 1, 2013 would include the HST impacts in rates going forward. If the Test Year's rate year begins May 1, entries to record variances in the sub-account of Account 1592 would cover the period from July 1, 2010 to April 30, 2013.

The applicant must provide an analysis that supports the applicant's conformity with December 2010 APH FAQs, in particular the example shown in FAQ #4.

The applicant must state whether entries have been made to record variances in the sub-account of Account 1592 to cover the period from July 1, 2010 to December 31, 2012 since the Test Year, which starts January 1, 2013 would include the HST impacts in rates going forward. If this is not the case, please explain. If the rate year begins May

1, entries to record variances in the sub-account of Account 1592 would cover the period from July 1, 2010 to April 30, 2013.

2.12.3 One-time Incremental IFRS Costs

For an applicant that files a 2013 cost of service application on the basis of MIFRS and is seeking recovery of one-time administrative incremental IFRS transition costs, or has such costs already reflected in base rates:

- Applicants that have one-time administrative incremental IFRS transition costs already included for recovery in its rates, must file for disposition of the balance in Account 1508, Other Regulatory Assets, “Sub-account IFRS Transition Costs Variance” reflecting the difference between the amounts recovered in rates and the actual incurred one-time administrative incremental IFRS transition costs.

- The applicant must provide a breakdown of the costs recorded in Account 1508 Other Regulatory Assets, Sub-account Deferred IFRS Transition Costs or Account 1508 Other Regulatory Assets, Sub-account IFRS Transition Costs Variance. The applicant must complete Appendix 2-U.

- The applicant must provide explanations for each category of costs recorded in the Deferred IFRS Transition Costs Account or IFRS Transition Costs Variance Account. The applicant must explain how the costs recorded meet the criteria of one-time IFRS administrative incremental costs.

- The applicant must provide explanations for material variances that may exist in the IFRS Transition Costs Variance account.

- Per the October 2009 APH FAQ #3 regarding costs that are permitted to be recorded in the Deferred IFRS Transition Costs Account and the IFRS Transition Costs Variance Account, the applicant must provide a confirmation statement that no capital costs, ongoing IFRS compliance costs, or impacts arising from adopting accounting policy changes are recorded in the Deferred IFRS Transition Costs Account or IFRS Transition Costs Variance Account. If this is not the case, the applicant must provide an explanation.

2.12.4 Account 1575 – IFRS-CGAAP Transitional PP&E Amounts

The applicant must propose a disposition period to “clear” the PP&E deferral account through a one-time adjustment to rate base to capture and remove the impact of the accounting policy changes as caused by the transition from CGAAP to MIFRS. The Board will determine the period of time for amortization on a case-by-case basis. The Board will be guided primarily by such considerations as the impact on rates, implications of any other IFRS transition matters, any requirements for rate mitigation including the impact on the distributor's customers and its cash flow position, and other matters such as intergenerational equity. No carrying charges will be applied to the balance in the PP&E account.

For an applicant that files a 2013 cost of service application on the basis of MIFRS:

- The applicant must provide evidence that indicates the IFRS-CGAAP Transitional PP&E Amount is to be cleared in rates as follows:

  - an adjustment to the test year depreciation expense (Appendix 2-CD or Appendix 2-CH, 2013 MIFRS Depreciation Expense) as part of distribution expenses for the amortization of Account 1575, and

  - an adjustment to the test year revenue requirement as part of the return on rate base component. The applicant must not record the return on rate base component in Account 1575 for accounting purposes.

- The Fixed Asset Continuity Schedule (Appendix 2-B) in the rate application must not be adjusted for balances related to the IFRS-CGAAP Transitional PP&E Amount.

- The applicant must provide a breakdown of the balance related to the IFRS-CGAAP Transitional PP&E Amount that is effective on the transition date to MIFRS. The applicant must provide the supporting analysis of the amounts in this account by completing Appendices 2-EA or 2-EB. The drivers of the change in closing net PP&E (CGAAP versus MIFRS) must be identified and quantified.

2.12.5 Disposition of Deferral and Variance Accounts

The applicant must:

- Identify all accounts for which it is seeking disposition;
- Identify any accounts for which the applicant is not proposing disposition and the reasons why;
- Propose rate riders for recovery or refund of balances that are proposed for disposition. The default disposition period is one year; if the applicant is proposing an alternative recovery period, an explanation should be provided;
- Indicate if the balances proposed for disposition before forecasted interest match the last Audited Financial Statements and provide explanations for any variances;
- Show all relevant calculations, including the rationale for the allocation of each account, the proposed billing determinants and the length of the disposition period; and

- Establish separate rate riders to recover the RSVA Power Account Global Adjustment from non-RPP customers.

In the event an applicant seeks an accounting order to establish a new deferral/variance account, the following eligibility criteria must be met:

- Causation - The forecasted expense must be clearly outside of the base upon which rates were derived.
- Materiality – The forecasted amounts must exceed the Board-defined materiality threshold and have a significant influence on the operation of the distributor; otherwise they should be expensed in the normal course and addressed through organizational productivity improvements.
- Prudence - The nature of the costs and forecasted quantum must be reasonably incurred although the final determination of prudence will be made at the time of disposition. In terms of the quantum, this means that the applicant must provide evidence demonstrating as to why the option selected represents a cost-effective option (not necessarily least initial cost) for ratepayers.

In addition, applicants must include a draft accounting order which must include a description of the mechanics of the account, including providing examples of general ledger entries, and the manner in which the applicant proposes to dispose of the account at the appropriate time.

2.12.6 Smart Meters

If the applicant is applying for smart meter-related recoveries, the applicant should refer to *Guideline G-2008-0011: Smart Meter Funding and Cost Recovery – Final Disposition*, or any successor document issued by the Board, with respect to any proposal to dispose, or partially dispose balances in accounts 1555 and 1556. In support of such proposals, the applicant must provide a completed smart meter model.

For those distributors that were subject to an IRM-based rate adjustment for their 2011 rates, the Board approved the continuation of any Smart Meter Funding Adder ("SMFA") to be in effect until no later than April 30, 2012. The Board has upheld the cessation of the SMFA as of April 30, 2012 in most decisions for 2012 IRM applications. The Board stated that distributors would be expected to file for a final prudence review of the costs in the smart meter variance accounts at the earliest possible opportunity following the availability of audited costs, since the deployment of smart meters on a province-wide basis is now nearing completion. Distributors scheduled to file cost of service applications for 2013 or later would be expected to apply for the disposition of smart meter costs, subsequent inclusion in rate base, and for recovery of stranded costs, in that application, if not previously addressed in a prior stand-alone or cost of service application.

Where a distributor has had some or all of its smart meter costs reviewed for prudence and approved for recovery in a previous cost of service or stand-alone application, the applicant should clearly document this, and in the latter case, should identify the specific adjustments to rate base and OM&A.

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Ontario Energy Board Commission de l'énergie de l'Ontario

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Ontario Energy Board

Chapter 3 of the Filing Requirements

For

Electricity Transmission and Distribution Applications

June 28, 2012

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Chapter 3 Filing Requirements for Incentive Regulation Mechanism Rate Applications

1.0 Introduction

The Ontario Energy Board establishes the rates of electricity distributors using a combination of annual incentive regulation mechanism ("IRM") adjustments and periodic cost of service reviews.

The Filing Requirements herein replace version 3.0 of Chapter 3 of the *Filing Requirements for Transmission and Distribution Applications* ("Filing Requirements"), dated June 22, 2011. The requirements set out the Board's expectations for filings by electricity distributors that are applying for annual rate adjustments under an IRM plan.

In its October 27, 2010 letter regarding the development of a Renewed Regulatory Framework for Electricity ("RRFE"), the Board announced that it was extending the 3rd Generation IRM ("IRM3") plan until such time as three RRFE policy initiatives have been substantially completed. As such, the four-year rate-setting cycle (i.e. rebasing plus three years of IRM) remains in place for the time being.

Version 3.0 of Chapter 3 of the Filing Requirements announced that the Board was no longer allowing distributors to file a 2nd Generation IRM application. The Board determined that the IRM3 plan would provide a uniform IRM framework to all distributors, including those that have not rebased since the 2006 EDR but elected to remain on an IRM plan. Hence, all IRM applications must be filed under IRM3.

1.1 Key References

The documents listed below are key to understanding these Filing Requirements:

- *Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation Mechanism for Ontario's Electricity Distributors* (filing guidelines: Appendix F) – December 20, 2006;
- *Report of the Board on the Cost of Capital for Ontario's Regulated Utilities*, December 11, 2009
- *Guidelines for Electricity Distributors' Conservation and Demand Management* (EB-2012-0003) – April 26, 2012;
- *Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors* – July 14, 2008;
- *Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors* – September 17, 2008;
- *Addendum to the Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors* – January 28, 2009;
- *Guideline (G-2008-0001) on Retail Transmission Service Rates* – October 22, 2008 (Revision 3.0 June 22, 2011 and any subsequent updates);
- *Guideline G-2011-0001:Smart Meter Funding and Cost Recovery – Final Disposition*, December 15, 2011;
- *Report of the Board on Electricity Distributors' Deferral and Variance Account Review Initiative (EDDVAR)* – July 31, 2009;
- *Filing Requirements: Distribution System Plans – Filing under Deemed Conditions of Licence* (EB-2009-0397) - May 17, 2012;
- *Report of the Board on Transition to International Financial Reporting Standards* EB-2008-0408 – July 28, 2009; and
- *Addendum to Report of the Board EB-2008-0408 – Implementing International Financial Reporting Standards in an Incentive Rate Mechanism Environment* – June 13, 2011 and the letter of the Board, dated April 30, 2012.

1.2 Grouping for Filings

Distributors that are seeking rate adjustments effective January 1, 2013 will be required to file their IRM application by August 3, 2012.

For those distributors that are seeking rate adjustments effective May 1, 2013, the Board will assign electricity distributors in one of six application groupings noted below based on the expected level of complexity of the application. The length of time required to review an application is commensurate upon its level of complexity. Applications of greater complexity and hence requiring more time to review will be required to be filed first. Staggering of the applications allows the Board and other stakeholders to appropriately schedule resources to allow for adequate review of the applications. The deadlines for filing an IRM application have been determined so that, in the normal course of events, a Decision and Order would be issued in time for a May 1 implementation date.

The application deadlines are as follows:

- Friday August 31, 2012
- Friday September 14, 2012
- Friday September 28, 2012
- Friday October 12, 2012
- Friday October 26, 2012
- Friday November 9, 2012

Board staff will survey potential IRM applicants in June 2012 requesting that applicants that are seeking rate adjustments effective May 1, 2013 identify the expected elements of their IRM application for the purpose of assisting the Board in assigning a filing deadline for each electricity distributor. Applicants expected to include one or more of the following elements in their application will be assigned an earlier filing date :

- LRAM to account for persistence of 2010 CDM programs in 2011 and 2012;
- LRAM Variance Account disposition;
- Rate Harmonization pursuant to a prior Board decision;
- Z Factor claim;
- Incremental Capital Module claim;
- Smart Meter Cost Recovery; and
- Renewable Generation and/or Smart Grid Rate Adder request.

The assignment of distributors under these filing dates will be identified in a separate communication.

1.3 Components of the Application Filing

Each application must include:

- A Manager's Summary thoroughly documenting and explaining all rate adjustments applied for;
- The contact information for the IRM application - The primary contact for the IRM application may be a person within the applicant's organization other than the primary licence contact. The Board will communicate with this person during the course of the application. After completion of the IRM application, the Board will revert communication to the primary licence contact;
- A completed Rate Generator[1] and supplementary work forms[2], provided by the Board, both in electronic (i.e. Excel) and PDF format;
- A PDF copy of the current Tariff Sheet;
- Supporting documentation cited within the application (e.g. excerpt of relevant past decisions and/or settlement agreements, relevant Reporting and Record-keeping Requirements ("RRR") data and Revenue Requirement Work Form ("RRWF"))[3];
- A statement as to which publication(s) the applicant's notice will be appearing, whether it is a paid publication or not and the readership and circulation numbers; and
- A text-searchable Adobe PDF format for all documents.

1.4 Bill Impacts

The Rate Generator includes a bill impact calculation by rate class and produces total bill impacts excluding any changes to the Regulated Price Plan ("RPP"). These calculations are similar to that used in assessing rate applications in recent years. The latest RPP at the time of publication of the Rate Generator model will be used and will remain unchanged for the duration of the application process.

[1] The Rate Generator is a Microsoft Excel workbook that calculates a distributor's proposed tariff of rates and charges in an IRM Application.
[2] Include the Shared Tax Savings Workform, Revenue Cost Ratio Adjustment Workform, Incremental Capital Module Workform, Deferral and Variance Account Workform and RTSR Adjustment Workform.
[3] The Revenue Requirement Work Form is filed as part of the draft rate order in the last rebasing application.

1.5 Applications and Electronic Models

The models issued by the Board are provided to assist the distributor in filing a rate application. An application to the Board is the distributor's responsibility and the Board expects that the application will be complete and accurate. While the Board may issue electronic filing models for use in IRM rate applications, the distributor bears the responsibility to ensure the accuracy and appropriateness of any models that it uses in supporting its application. The distributor is responsible for advising the Board of any concerns it may have regarding calculations flowing from the models. Utilization of the models issued by the Board does not necessarily constitute Board acceptance.

1.6 Other Rate Adjustments

The Rate Generator will be made available on the Board's web site. The model will include generic base rate adjustments, rate adders and rate riders common to most applicants. Where a distributor has continuing adjustments, and/or rate adders and/or rate riders from previous decisions that are not in the generic model (such as the phased implementation of a rate harmonization process) the distributor should contact Board staff for specific guidance.

2.0 Elements of the IRM Plan

2.1 Price Cap Index Adjustment

The Gross Domestic Product Implicit Price Index for Final Domestic Demand (GDP-IPI) as published by Statistics Canada will be used as the price escalator for IRM applications.

For rates effective January 1, 2013, the GDP-IPI will be the annual percentage change in the GDP-IPI for the period 2011 Q3 to 2012 Q2 to 2010 Q3 to 2011 Q2. For rates effective May 1, 2013, the GDP-IPI will be the annual percentage change for calendar year 2012.

The Rate Generator will originally include the preceding calendar year's GDP-IPI value as an estimate of the inflationary adjustment to input prices (i.e. costs) for the upcoming rate year. Statistics Canada typically publishes data approximately two months following a period. Upon publication by Statistics Canada, the Board will issue a letter establishing the updated GDP-IPI. Board staff will update the GDP-IPI in each distributor's Rate Generator in order to calculate the price cap index adjustment for final distribution rates for all applicants. Distributors will have an opportunity to comment on the accuracy of Board staff's update as part of the draft Rate Order process.

The price cap index adjustment is determined as the annual percentage change in the GDP-IPI less the X-Factor. The X-factor is 0.72% plus a stretch factor. The value of the stretch factor is specific to each distributor for each rate year, and will be one of the following values: 0.2%; 0.4%; or 0.6%. The Board will determine each distributor's stretch factor. The distributor specific stretch factors will not be available before the application is filed. Therefore, the Rate Generator will include a proxy stretch factor of 0.4%. Once the distributor specific stretch factors become available, Board staff will adjust the stretch factor in each distributor's individual Rate Generator. Distributors will have an opportunity to comment on the accuracy of Board staff's update as part of the draft Rate Order process.

The price cap index adjustment will not be applied to the following components of delivery rates:

- Rate Adders;
- Rate Riders;
- Low Voltage Service Charges;
- Retail Transmission Service Rates;
- Wholesale Market Service Rate;
- Rural Rate Protection Charge;
- Standard Supply Service – Administrative Charge;
- MicroFIT Service Charge;
- Specific Service Charges; and
- Transformation and Primary Metering Allowances.[4]

2.2 Incremental Capital Module

The incremental capital module ("ICM") is intended to address the treatment of new capital investment needs that arise during the IRM plan term which are incremental to the materiality threshold defined below.

The eligibility criteria to recover amounts that are incremental to capital investment needs are included in section 2.5 of the *Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors, dated* July 14, 2008 and are reproduced below.

4 and any other allowances the Board may determine.

Criteria	Description
Materiality	The amounts must exceed the Board-defined materiality threshold and clearly have a significant influence on the operation of the distributor; otherwise they should be dealt with at rebasing.
Need	Amounts should be directly related to the claimed driver, which must be clearly non-discretionary. The amounts must be clearly outside of the base upon which rates were derived.
Prudence	The amounts to be incurred must be prudent. This means that the distributor's decision to incur the amounts must represent the most cost-effective option (not necessarily least initial cost) for ratepayers.

2.2.1 ICM Materiality Threshold

The ICM materiality threshold is discussed in section 2.3 of the *Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors* (the "Supplemental Report") EB-2007-0673.

The Board has determined that the following formula is to be used by a distributor to calculate the materiality threshold that will apply to it:

$$\textit{Threshold Value} = 1 + \left(\frac{RB}{d}\right) * (g + PCI * (1 + g)) + 20\%$$

Where:

RB = rate base included in base rates ($);

d = depreciation expense included in base rates ($);

g = distribution revenue change from load growth (%); and

PCI = price cap index (% inflation less productivity factor less stretch factor).

The values for "RB" and "d" are the Board-approved amounts in the distributor's base year rate decision.

The value for "g" is the % difference in distribution revenues between the most current complete year and the base year.

The following table provides an example of the calculation of the materiality threshold values.

An Illustration:			
Assumptions:	RB	=	\$100 million;
	d	=	\$5 million;
	g	=	1.5% (0.015); and
	PCI	=	0.75% (0.0075).
Calculation:	$1+(\frac{100{,}000{,}000}{5{,}000{,}000})*(0.015+.0075*(1+0.015))+0.20=1.65$		
Result:	The materiality threshold (CAPEX/Depreciation) is 1.65 or 165%. That is, given the assumptions in this example, the Board expects the distributor to manage a CAPEX level of up to \$8.26 million (\$5 million * 1.65) before being eligible to apply to recover incremental amounts.		

2.2.2 Eligible Incremental Capital Amount

In the Supplemental Report, the Board determined that eligible incremental capital amount sought for recovery should be new capital in excess of the materiality threshold. The materiality threshold value, as calculated using the formula discussed in Section 2.2.1, establishes eligibility for incremental capital spending and also marks the base from which to calculate the maximum amount eligible for recovery. A distributor applying for recovery of incremental capital should calculate the maximum allowable capital amount by taking the difference between the 2013 total non-discretionary capital expenditure and the materiality threshold.

2.2.3 Application of the Half-Year Rule

The Board's general guidance on the application of the half-year rule is provided in the Supplemental Report. In this report the Board determined that the half-year rule should not apply so as not build a deficiency for the subsequent years of the IRM plan term. In a subsequent decision with respect to the application of the half-year rule in the context of an ICM, the Board decided that the half-year rule would apply in the final year of the IRM plan term[5]. The Board has adopted this as a clarification to the policy on ICM.

2.2.4 Revenue Requirement Calculation

When calculating the revenue requirement associated with the ICM, a distributor should use the following parameters:

- Cost of Capital
    - In the *Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors*, issued

[5] EB-2010-0130, Guelph Hydro Electric Systems Inc., *Decision and Order,* p. 15

December 20, 2006 ("2006 Report") the Board outlined the transition to a single deemed capital structure of 60% debt and 40% equity. Since all distributors have completed the transition to a 60/40 debt-equity ratio, a distributor filing for an ICM adjustment shall use this deemed capital structure.

- On December 11, 2009 the Board issued the *Report of the Board on the Cost of Capital for Ontario's Regulated Utilities* (the "2009 Report"). The 2009 Report sets out revised cost of capital parameters to be effected in cost of service applications. A distributor filing an ICM adjustment, shall use the last Board-approved cost of capital parameters determined during the distributor's last rebasing application when calculating the revenue requirement associated with the ICM.

- PILS
  - Since currently known legislated tax changes from the level reflected in the Board-approved base rates for a distributor will be reflected in the IRM adjustments, a distributor filing for an ICM adjustment should apply the current tax rates when calculating the revenue requirement associated with the ICM.

- Working Capital Allowance ("WCA")
  - A distributor filing an ICM adjustment shall use the last Board-approved WCA determined during the distributor's last rebasing application when calculating the revenue requirement associated with the ICM.

2.2.5 ICM Filing Guidelines

The Board requires that a distributor requesting relief for incremental capital during the IRM3 plan term must include comprehensive evidence to support the claimed need, which should include the following:

- An analysis demonstrating that the materiality threshold test has been met and that the amounts will have a significant influence on the operation of the distributor;
- Justification that the amounts to be incurred will be prudent. This means that the distributor's decision to incur the amounts represents the most cost-effective option (not necessarily least initial cost) for ratepayers;
- Justification that amounts being sought are directly related to the claimed cause, which must be clearly non-discretionary and clearly outside of the base upon which current rates were derived.

- Evidence that the incremental revenue requested will not be recovered through other means (e.g., it is not, in full or in part, included in base rates or being funded by the expansion of service to include new customers and other load growth);
- Details by project for the proposed capital spending plan for the test year segregated between discretionary and non-discretionary;
- A description of the proposed non-discretionary capital projects and expected in-service dates;
- Calculation of the revenue requirement associated with each proposed incremental non-discretionary capital project (i.e. the cost of capital, depreciation, and PILs);
- Calculation of revenue requirement offsets associated with each incremental non-discretionary projects due to revenue to be generated through other means (e.g. customer contributions in aid of construction);
- A description of the actions the distributor will take in the event that the Board does not approve the application.
- Calculation of a rate rider to recover the incremental revenue from each class and the rationale for the proposed approach.

2.2.6 ICM Reporting Requirements

A distributor that receives rate relief through this module will be required to report to the Board annually on the actual amounts spent. At the time of the next rebasing, the distributor will file a calculation of the amounts to be incorporated in rate base. At that time the Board will make a determination on the treatment of any difference between forecast and actual capital spending during the IRM plan term. Any overspending or underspending will be reviewed at the time of rebasing.

2.2.7 ICM Accounting Treatment

The distributor will record eligible ICM amounts in Account 1508, Other Regulatory Asset, sub-account Incremental Capital Expenditures, subject to the assets being used and useful. For incremental capital assets under construction, the normal accounting treatment will continue in the construction work in progress (“CWIP”) prior to these assets going into service and hence eligible for recording in the 1508 sub-account. The amortization of capital assets for the relevant accounting period will be recorded in a separate amortization account of the sub-account, Incremental Capital Expenditures. In addition, the revenues collected from the rate rider will be recorded in Account 1508, Other Regulatory Asset, sub-account, Incremental Capital Expenditures rate rider.

The distributor shall also record monthly carrying charges in sub-accounts Incremental Capital Expenditures and Incremental Capital Expenditures rate rider. Carrying charges amounts are calculated using simple interest applied to the monthly opening balances in the account and recorded in a separate sub-account of account 1508. The rate of interest shall be the rate prescribed by the Board for deferral and variance accounts for the respective quarterly period published in the Board's web site.

2.2.8 Rate Generator and Supplemental Filing Module for ICM

The supplemental filing module supporting the Rate Generator will assist the distributor in calculating the distributor's threshold. The distributor will then tabulate the value of its eligible non-discretionary investments and compare this to the threshold. Other calculation work forms will be provided to calculate the revenue requirement for each project proposed for inclusion in the ICM request in the supplemental filing module. Once all work forms are completed and listed in the supplemental module, the tabulated revenue requirement will be converted into a rate rider.

2.3 Z-factor Claims

Z-factors are intended to provide for unforeseen events outside of a distributor's management control. The cost to a distributor must be material and its causation clear. A distributor must follow the guidelines listed below when applying to the Board to recover the amounts that the distributor has recorded in a Board-approved deferral account related to a Z-factor claim.

2.3.1 Eligibility Criteria for Z-factor Amounts

The eligibility criteria for a request to recover amounts by way of a Z-factor are discussed in section 2.6 of the *Board's Report on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors* – July 14, 2008, and are summarized in Table 1 below. In order for amounts to be considered for recovery by way of a Z-factor, the amounts must satisfy all three eligibility criteria set out in Table 1 below.

Table 1: Z-factor Amount Eligibility Criteria

Criteria	**Description**
Causation	Amounts should be directly related to the Z-factor event. The amount must be clearly outside of the base upon which rates were derived.
Materiality	The amounts must exceed the Board-defined materiality threshold and have a significant influence on the operation of the distributor; otherwise they should be expensed in the normal course and addressed through organizational productivity improvements.
Prudence	The amount must have been prudently incurred. This means that the distributor's decision to incur the amount must represent the most cost-effective option (not necessarily least initial cost) for ratepayers.

2.3.2 Materiality Threshold

The following materiality thresholds will apply:

- $50,000 for a distributor with a distribution revenue requirement less than or equal to $10 million;
- 0.5% of distribution revenue requirement for a distributor with a revenue requirement greater than $10 million and less than or equal to $200 million; and
- $1 million for a distributor with a distribution revenue requirement of more than $200 million.

The materiality threshold must be met on an individual event basis in order for the relevant costs to be eligible for potential recovery.

2.3.3 Z-factor Filing Guidelines

A distributor must submit evidence that the costs incurred meet the three eligibility criteria outlined above. A distributor must also:

- Notify the Board by letter to the Board Secretary of all Z-factor events. Failure to notify the Board within six months of the event may result in disallowance of the claim.
- Apply to the Board for any cost recovery of amounts recorded in the Board-approved deferral account claimed under Z-factor treatment. This will allow the Board and any affected distributor the flexibility to address extraordinary events in a timely manner. Subsequently, the Board may review and prospectively adjust the amounts for which Z-factor treatment is claimed.
- Provide a clear demonstration that the management of the distributor could not have been able to plan and budget for the event and that the harm caused by the event is genuinely incremental to its experience or reasonable expectations.
- Demonstrate that the costs are incremental to those already being recovered in rates as part of ongoing business exposure risk.

2.3.4 Other Matters in Relation to Z-Factors

As part of its claim, a distributor must outline the manner in which it intends to allocate the incremental revenue requirement to the various customer rate classes, the rationale for the selected approach and a discussion of the merits of alternative allocation methods. Recovery will be through a rate rider[6]. The request must specify whether the rate rider(s) will apply on a fixed or variable basis or a combination thereof, and the

[6] See Appendix C

length of the disposition period and a rationale for this proposal. A detailed calculation of the rate rider(s) must be provided.

2.3.5 Z-factor Accounting Treatment

The distributor will record eligible Z-factor cost amounts in Account 1572, Extraordinary Event Costs, of the Board's Uniform System of Accounts (the "USoA") contained in the *Accounting Procedures Handbook* ("APH") for electricity distributors. Monthly carrying charges shall be recorded in Account 1572. Carrying charges are calculated using simple interest applied to the monthly opening balances in the account and recorded in a separate sub-account of this account. The rate of interest shall be the rate prescribed by the Board for deferral and variance accounts for the respective quarterly period published on the Board's web site.

2.4 Off-ramps

An off-ramp is based on a pre-defined set of conditions under which the IRM plan would be terminated or modified before its normal end-of-term date due to excessive over or under earnings.

For IRM3, the Board determined that the plan will include a trigger mechanism with an annual ROE dead band of ±300 basis points. When a distributor performs outside of this earnings dead band, a regulatory review may be initiated. A distributor will be required to report to the Board no later than 60 days after the company's receipt of its annual audited financial statements, in the event that the distributor's earnings falls short of or exceeds its ROE by 300 basis points. The Board will also monitor results filed by distributors as part of their reporting and record-keeping requirements. A review will be carried out by the Board to determine if further action by the Board is warranted. Any such review would be prospective in nature, and could result in modifications to the IRM3 plan, a termination of the IRM3 plan or the continuation of the IRM3 plan for that distributor.

2.5 Tax Changes

Under an IRM3, a 50/50 sharing[7] of the impact of currently known legislated tax changes as applied to the tax level reflected in the Board-approved base rates for a distributor applies. The calculated annual tax changes over the plan term will be allocated to customer rate classes on the basis of the most recent Board-approved base-year distribution revenue. These amounts will be collected from or refunded to customers each year of the plan term, over a 12-month period, through an explicit volumetric rate rider derived using annualized consumption by customer class underlying the Board-approved base rates.

[7] Supplemental Report of the Board on 3rd Generation Incentive Regulation – September 17, 2008

A shared tax saving workform will include a schedule for a distributor to complete, which will calculate the volumetric rate rider. Occasionally, the calculated rate riders for one or more rate classes may be negligible. In the event that the calculation for one or more rate classes results in volumetric rate riders of $0.0000 when rounded to the fourth decimal place, or is negligible, the distributor may request to record the total amount in USoA account 1595 for disposition in a future proceeding.

3.0 Implementation Matters

3.1 Deferral and Variance Account Balances

The *Report of the Board on Electricity Distributors' Deferral and Variance Account Review Report* (the "EDDVAR Report") provides that during the IRM plan term, the distributor's Group 1 audited account balances will be reviewed and disposed if the preset disposition threshold of $0.001 per kWh (debit or credit) is exceeded. The onus is on the distributor to justify why any account balance in excess of the threshold should not be disposed.

Distributors must file in their application Group 1 balances as of December 31, 2011 to determine if the threshold has been exceeded. A continuity schedule, found on sheet 9 of the Rate Generator, must be completed as part of the application, regardless of whether or not the preset disposition threshold has been met.

Group 1 consists of the following USoA accounts:

- 1550 Low Voltage Account;
- 1580 RSVA Wholesale Market Service Charge Account;
- 1584 RSVA Retail Transmission Network Charges Account;
- 1586 RSVA Retail Transmission Connection Charge Account;
- 1588 RSVA Power Account;
- 1588 RSVA Global Adjustment Sub-Account;
- 1590 Recovery of Regulatory Asset Balances Account; and
- 1595 Disposition and Recovery/Refund of Regulatory Balances Account.

The EDDVAR Report states that the default disposition period to clear the Group 1 account balances by means of a rate rider should be one year. However, a distributor could propose a different disposition period to mitigate rate impacts or address any other applicable considerations, where appropriate.

The global adjustment sub-account captures the difference between the amounts billed (or estimated to be billed) to non-RPP customers by the distributor and the actual amount paid by the distributor to the IESO.

During the 2010, 2011, and 2012 EDR process, the Board determined that a separate rate rider included in the delivery component of the bill would apply prospectively to non-RPP customers to dispose of the global adjustment sub-account balances.

In March of 2012, the Board updated the APH. The Board revised Account 1588 RSVA Power, Sub-account Global Adjustment and established a separate account for the global adjustment, Account 1589, RSVA Global Adjustment, effective January 1, 2012. Since balances as of December 31, 2011 will be subject to the Board's review as part of the 2013 IRM application, this change will apply to 2014 rate applications only.

3.2 Revenue-to-Cost Ratio Adjustments

The Board's Decisions for some distributors' 2010, 2011 and 2012 cost of service rate applications prescribed a phase-in period to adjust the revenue-to-cost ratios. The Supplemental Filing Module and Rate Generator will include schedules for a distributor to effect revenue-to-cost ratio adjustments previously approved by the Board. The process will adjust base distribution rates before the application of the price cap adjustment.

3.3 Electricity Distribution Retail Transmission Service Rates

In preparing its application, the distributor should reference the Board's *Guideline G-2008-0001: Electricity Distribution Retail Transmission Service Rates,* October 22, 2008, and subsequent updates to the Uniform Transmission Rates ("UTRs").

The Board will provide a filing module to distributors to assist in calculating the distributor's class-specific RTSRs. The filing module will reflect the most recent UTRs approved by the Board (EB-2011-0268), issued on December 20, 2011 and effective January 1, 2012. Once any January 1, 2013 UTR adjustments are determined, Board staff will adjust each distributor's 2013 RTSR model and Rate Generator to incorporate these changes. Distributors will have an opportunity to comment on the accuracy of Board staff's updates as part of the draft Rate Order process.

3.4 Conservation and Demand Management ("CDM") Costs

The CDM Code was issued on September 16, 2010 and sets out obligations and requirements in relation to CDM activities after December 31, 2010. The CDM Code applies to CDM Programs that start on January 1, 2011 and end on December 31, 2014 or occur anytime in between those two dates. All electricity savings (kWh) and peak demand savings (kW) resulting from CDM Programs must also occur within that timeframe to be counted against a distributor's CDM Targets.

The Board expects that, going forward, most CDM funding for distributors for the 2012-2014 period, will be provided by the Ontario Power Authority ("OPA"). It is expected that a distributor will enter into contracts to deliver OPA-Contracted Province-Wide CDM Programs. If a distributor seeks to deliver programs not being offered through the OPA-Contracted Province-Wide Programs, it is able to apply for Board approval for programs that are in compliance with the rules set out in the Board's CDM Code and clarified in the April 26, 2012 Conservation and Demand Management Guidelines (EB-2012-0003) (CDM Guidelines). This will be funded through the global adjustment mechanism, and therefore should not be included in distribution rates.

3.4.1 Lost Revenue Adjustment Mechanism

The lost revenue adjustment mechanism ("LRAM") is a retrospective adjustment, which is designed to account for differences between the forecast revenue loss embedded in rates and the actual revenue loss.

On April 26, 2012, the Board issued updated CDM Guidelines. The CDM Guidelines were developed to provide more clarity on the CDM Code and what information needs to be filed in support of Board-Approved CDM program applications, as well as to provide updated details on the LRAM and the associated variance account for the 2011-2014 term.

3.4.2 LRAM Variance Account ("LRAMVA") for 2011 – 2014

For CDM programs delivered within the 2011 to 2014 term, the Board established Account 1568 as the LRAMVA to capture the variance between the Board-approved CDM forecast and the actual results at the customer rate class level. Accounting guidelines regarding the LRAMVA can be found in Appendix B of the 2012 CDM Guidelines. Distributors should refer to the CDM Guidelines for further details.

The distributor shall compare the Board-approved forecasted CDM related load forecast reduction to the actual CDM results. The variance calculated from this comparison shall be recorded in separate sub-accounts for the applicable customer rate classes.

3.4.3 Disposition of the LRAMVA

At a minimum, distributors must apply for the disposition of the balance in the LRAMVA as part of their COS applications. Distributors may apply for the disposition of the balance in the LRAMVA on an annual basis, as part of their IRM rate applications, if the balance is deemed significant by the applicant.

In support of its application for lost revenues distributors must file the following:

- A statement indicating that the distributor has used the most recent input assumptions available at the time of the program evaluation when calculating its

LRAM amount;

- A statement indicating that the distributor has relied on the most recent and appropriate final evaluation report from the OPA in support of its LRAM calculation;

- Separate tables for each rate class that shows the LRAM amounts requested by the year they are associated with and the year the lost revenues took place;

- LRAM calculations, determined by calculating the energy savings by customer class and valuing those energy savings using the distributor's Board-approved variable distribution charge appropriate to the class;

- A statement, and if applicable a table, that indicates if carrying charges are being requested on the LRAM amount;

- For Board-approved programs, a third party report, in accordance with the OPA's EM&V Protocols as set out in Section 6.1 of the CDM Code, that provides a review and verification of the LRAM calculations, including:

    - Confirmation of the use of correct input assumptions and LRAM calculations
    - Verified participation amounts
    - The net and gross kW and kWh impacts of each program and for each class, both gross and net of free riders, separated by year
    - Verification of any carrying charges requested; and

- For OPA Contracted Province-Wide Programs the distributor must provide documentation (i.e. final evaluation report from the OPA) of the distributor's results.

A separate third party review of the distributors OPA-Contracted Province-Wide CDM programs is not required.

3.4.4 LRAM and/or SSM for pre-2011 CDM activities

In Section 3.4.2 of Chapter 3 of the Filing Requirements, issued June 22, 2011, the Board stated that if a distributor does not file for the recovery of LRAM or SSM amounts in its 2012 rate application, it will forego the opportunity to recover LRAM or SSM for the legacy period of CDM activity (2005 – 2010).

The Board expects LRAM claims for pre-2011 CDM activities to have been completed with the 2012 rate applications, outside of persisting historical CDM impacts realized after 2010 for those distributors whose load forecast has not been updated as part of a cost of service application. SSM is not applicable for savings persisting from the legacy period.

In support of its application for persisting lost revenues from pre-2011 CDM programs, distributors must file the following:

- A statement confirming that the distributor's load forecast has not been updated as part of a cost of service application since the CDM programs, for which persistent lost revenue is sought, were implemented;
- A statement indicating that the distributor has used the most recent input assumptions available at the time of the program evaluation when calculating its LRAM amount;
- A statement indicating that the distributor has relied on the most recent and appropriate final evaluation report from the OPA in support of its LRAM calculation;
- Separate tables for each rate class that shows the LRAM amounts requested by the year they are associated with and the year the lost revenues took place;
- LRAM calculations, determined by calculating the energy savings by customer class and valuing those energy savings using the distributor's Board-approved variable distribution charge appropriate to the class;
- A statement, and if applicable a table, that indicates if carrying charges are being requested on the LRAM amount;
- A third party report that provides a review and verification of the LRAM calculations, including:
    - Confirmation of the use of correct input assumptions and LRAM calculation
    - Verified participation amounts
    - The net and gross kW and kWh impacts of each program and for each class, both gross and net of free riders, separated by year
    - Verification of any carrying charges requested.

3.5 Distribution System Plans - Filing under Deemed Conditions of Licence

The *Filing Requirements: Distribution System Plans - Filing under Deemed Conditions of Licence* (EB-2009-0397) revised on May 17, 2012 (originally issued on March 25, 2010), recognized that distributors may need additional funding for expenditures proposed in a GEA Plan between cost-of-service applications. For 2013 IRM applications, distributors may request the following:

- Renewable Generation Connection Funding Adder; and
- Smart Grid Funding Adder.

Where a distributor seeks a funding adder, sufficient information must be provided to allow the Board to assess the need for the mechanism and the nature and quantum of the costs to be collected from ratepayers and the basis for calculating the funding adder. The costs recovered through the funding adder will be subject to a prudence review in the first cost of service application following the implementation of the funding adder. A refund to ratepayers may be ordered if the Board find that the expenditures upon which the adder was based were not prudently incurred.

In the Distribution System Plan Filing Requirements, the Board created two additional deferral accounts to record the amounts collected from ratepayers through the funding adders:

- Account 1533: Renewable Generation Connection Funding Adder Deferral Account

  This account will record the revenues collected through a funding adder approved by the Board related to renewable generation connection projects. Separate sub-accounts shall be used to record any amounts collected from a distributor's ratepayers and any amounts received from the IESO (pursuant to the provincial pooling mechanism set out in 79.1 of the OEB Act) in respect of the projects.

- Account 1536: Smart Grid Funding Adder Deferral Account
  This account will record the revenue collected through a funding adder approved by the Board related to smart grid development.

3.6 Transition to International Financial Reporting Standards ("IFRS")

The Board provided general guidance on this topic in the *Report of the Board, Transition to IFRS,* issued on July 28, 2009 and in associated amendments available on the IFRS page of the Board's website (amendments are dated November 8, 2010 and April 30, 2012).

On June 13, 2011 an *Addendum to Report of the Board: Implementing International Financial Reporting Standards in an Incentive Rate Mechanism Environment* (EB-2008-0408) (the "Addendum") was issued following a working group process. The Addendum sets out additional regulatory policy regarding the transition to IFRS in the circumstance where utilities rates are rebased using cost of service rate setting methods and where rates are subsequently set using an IRM. For distributors that rebased under CGAAP and are filing an IRM application, issues 1 and 2 in the Addendum are of particular relevance.

For those distributors who rebased under CGAAP and are filing an IRM application where a distributor seeks an ICM, and/or Z-factor treatment, the financial information supporting the rate adjustments must be provided under CGAAP. The adjustments to rates will also be made on the basis of CGAAP.

In addition, a reconciliation of the CGAAP-based financial information for an ICM or Z factor to the relevant information in the last annual RRR reporting under modified IFRS is required. Where the applicant has adopted IFRS for financial reporting, but has not yet made an annual RRR reporting under modified IFRS, the financial information mentioned above must be provided in both CGAAP and modified IFRS format, and a reconciliation provided between the two accounting standards. No third party assurance is required for the reconciliations, although an applicant can choose to file such assurance as part of its evidence supporting the reconciliation.

The Board authorized the creation of a generic IFRS transition PP&E deferral account, Account 1575, that the applicants must use to record differences arising as a result of accounting policy changes caused by the transition from CGAAP to MIFRS. In general, this account will be cleared at the first rebasing application under MIFRS.

Utilities that file and report under USGAAP (or another accounting standard) should, in general, read references to IFRS and MIFRS in the Filing Requirements to include USGAAP (or other alternate accounting standard). The deferral account authorized in Issue 2 of the Addendum may not be necessary for such utilities.

4.0 Specific Exclusions from IRM Applications

The IRM application process is intended to streamline the processing of a large volume of rate adjustment applications, and is therefore intended to be mechanistic in nature. For this reason, the Board has determined that the IRM process is not the appropriate venue by which a distributor should seek relief on issues which are substantially unique to an individual distributor or more complicated and potentially contentious. The following are examples of specific exclusions from the IRM rate application process:

- Rate Harmonization, other than that pursuant to a prior Board decision;
- Changes to revenue-to-cost ratios, other than pursuant to a prior Board decision;
- Loss Factor Changes;
- Re-setting of Specific Service Charges;
- Loss Carry Forward Adjustments to PILs/taxes; and
- Loss of Customer Load.

Exclusions from the IRM process are to be addressed in the distributor's next cost of service application. With respect to smart meter cost recovery, a distributor may elect to include this element as part of its 2013 IRM application if the timing of the smart meter cost recovery application coincides with the filing of the IRM application. Otherwise, the review of smart meter costs should be addressed in a separate (or stand alone) application.

Appendix A: Disposition of Residual Balance in USoA Account 1590 or 1595

The 2006 Regulatory Assets process disposed of all balances in the regulatory asset accounts as of December 31, 2004. The decisions for each distributor resulted in the disposition of the approved amounts by way of final rate riders and the transfer of the approved amounts to account 1590. Likewise, any deferral and variance account balances post December 31, 2004 that have been approved by the Board for disposition were disposed on a final basis, unless otherwise noted and should have been transferred to account 1595.

Accounts 1590 and 1595 are part of the Group 1 deferral and variance accounts as defined by the Board in the EDDVAR Report. Once the rate rider ceases, the residual principal balances and any interest carrying charges in these accounts would be cleared in an IRM application (where applicable) provided that the preset disposition threshold for the Group 1 accounts has been exceeded.

Appendix B: Application of Recoveries to Principal and Interest Carrying Charges Amounts in Account 1595

When final approval for disposition of deferral and variance account balances is received from the Board, the final approved amounts of principal and interest carrying charges is transferred to account 1595.

The cumulative principal balance transferred to account 1595 is drawn down by the rate rider recoveries, and interest carrying charges are applied to the principal balance net of recoveries.

The following approach is used for the application of recoveries (via rate riders) to the transferred amounts under two scenarios:

Scenario 1: Rate Rider ceases with Principal amount remaining.

If the rate rider ends before the principal is fully drawn down, the principal balance is held static and interest carrying charges are applied to the remaining principal balance. The approved rate rider flowing from the next application to dispose of deferral and variance accounts should include the remaining principal and interest carrying charges.

Scenario 2: Rate Rider ceases with no Principal amount remaining but with Interest Carrying Charges remaining.

The approved rate rider flowing from the next application to dispose of deferral and variance account balances should include the cumulative interest carrying charge amounts.

Appendix C: Rate Adder versus Rate Rider

Rate Adder

A rate adder (or funding adder) is a tool designed to provide advance funding on an interim basis to distributors for certain investments or expenses as prescribed by the Board and to mitigate or smooth the anticipated rate impact when recovery of these costs are approved by the Board. Approval of a rate adder does not constitute regulatory approval of any costs actually incurred. The prudence of such costs is examined, and the costs are approved in whole or in part, at the time at which the distributor brings the matter forward for regulatory review.

Rate adders are identified and listed separately on a distributor's Tariff of Rates and Charges and may have a sunset or termination date.

Rate Rider

A rate rider differs from a rate adder in that it is designed to recover or refund Board-approved amounts following a prudence review. Rate riders are identified and listed separately on a distributor's Tariff of Rates and Charges, with an explicit sunset or termination date.

Materiality for Rate Adders and Rate Riders

Rate adders and rate riders normally apply to one or more select rate classes on a fixed basis, a volumetric basis or a combination of both. A rate adder or rate rider is usually determined by dividing the Board-approved allocated amounts by the Board-approved forecast or historical energy use or demand.

Occasionally, the calculated rate adders or rate riders for one or more rate classes may be negligible. In the event where the calculation of one or more rate adder or rate rider results in volumetric rate riders of $(0.0000) when rounded to the fourth decimal place, , or are negligible the entire Board-approved amount for recovery or refund shall be recorded in a USoA account to be determined by the Board for disposition in a future rate setting.

Ontario Energy Board

Commission de l'énergie de l'Ontario

Ontario Energy Board

Chapter 4 of the Filing Requirements For Electricity Transmission and Distribution Applications

May 17, 2012

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Chapter 4 Minimum Filing requirements for electricity transmission projects under Section 92 of the Ontario Energy Board Act (“the Act”)

4.1 Introduction

The Act requires transmitters and distributors to obtain leave of the Board for the construction, expansion, or reinforcement of electricity transmission and distribution lines or interconnections; however, Ontario Regulation 161/99 has specified that this requirement applies only to transmission lines greater than 2 kilometres in length. A transmission system is defined as a system for conveying electricity at voltages greater than 50 kilovolts (“kV”).

The filing requirements set out in this document are not intended to limit applicants in terms of what information they may want to present. Nor do these filing requirements limit the discretion of the Board in terms of what information and evidence it may wish to see.

In addition to the need to obtain leave to construct, under section 81 of the Act, any generator or an affiliate of a generator planning to construct transmission facilities must give notice to the Board per guidelines available on the Board’s website **www.ontarioenergyboard.ca/documents/cases/Maad/guidelines.pdf**. The Board upon examining the relevant facts may choose to formally review the application by holding a hearing, and in that event will advise the applicant within 60 days of receiving the application of its intention to formally review that application.

Construction of new transmission facilities may also require an amendment to a transmitter license issued by the Board.

Any person who obtained leave of the Board to construct facilities under section 92 or who is exempt under section 95 may apply to the Board for authority to expropriate land for that purpose.

The Board’s role in assessing applications for leave to construct transmission lines under section 92 is to ensure that the proposed projects are in the “public interest”. Section 92:

> **92.** (1) No person shall construct, expand or reinforce an electricity transmission line or an electricity distribution line or make an interconnection without first obtaining from the Board an order granting leave to construct, expand or reinforce such line or interconnection. 1998, c. 15, Sched. B, s. 92 (1).

Note, however, that subsection 96(2) specifies that for section 92 purposes in determining whether the construction, expansion or reinforcement of the electricity transmission line or interconnection is in the public interest, the Board shall only consider the following:

> "1. The interests of consumers with respect to prices and the reliability and quality of electricity service."
>
> 2. Where applicable and in a manner consistent with the policies of the Government of Ontario, the promotion of the use of renewable energy sources."

4.2 The Regulatory Framework

4.2.1 Legislation

Section 92 of the Act requires leave of the Board for the construction, expansion, or reinforcement of an electricity transmission line or an electricity distribution line, as well as for the making of a connection to the power system. Under Ontario Regulation 161/99 however, many projects that would otherwise require approval under s. 92 of the Act are exempt from the need for leave to construct. This includes all distribution projects and most connections and projects involving electricity transmission lines that are 2 kilometres or less in length.

Section 95 of the Act allows an applicant to seek an exemption from the requirements of s. 92 of the Act. An applicant must submit such a request accompanied by the special circumstances that warrant an exemption from the requirement to obtain leave to construct under s. 92 of the Act. A project summary report should be submitted for review, consistent with the requirements described in this document. The level of detail in the submission should reflect the issues or concerns encountered during the evaluation phase of the project.

Section 97 requires that information on land requirements must be included as part of the leave to construct application. Section 97 of the Act states, "leave to construct shall not be granted until the applicant satisfies the Board that it has offered or will offer to each owner of land affected by the approved route or location an agreement in a form approved by the Board."

4.2.2 Related Regulatory Hearings

Board review of transmission investment can arise in regulatory settings other than a leave to construct application. For example, the Board's authority to review transmitter's capital budgets and set rates is established in subsection 78 (1) of the Act which states "No transmitter shall charge for the transmission of electricity except in accordance with an order of the Board, which is not bound by the terms of any contract."

Avoiding duplication of regulatory review is therefore critical. The conclusions of the Board specific to a project that are made in one regulatory proceeding will not generally be re-evaluated in another proceeding. However, this must have been a discreet finding of the Board in a previous decision, not simply that information was filed in an application. For example, if the need for a project is clearly established in a leave to construct application, this need would not need to be re-evaluated in a subsequent rate proceeding to determine transmission rates; and to the extent that the project's costs and timing had not changed, the Board's review of these may not need to be comprehensive. However, if the leave to construct is preceded by the transmitter's rate case, the need for the project may not have been dealt with in sufficient detail to satisfy the requirements of a leave to construct proceeding. If the project had received approval in a rate hearing as part of an envelope of expenditures rather than as a discreet approval of the particular project, that panel would likely revisit the valuation of the project in some detail. The intent, however, is not to re-assess that which has already been specifically addressed in a related proceeding.

In addition to a leave to construct approval, most transmission projects will require various other regulatory approvals: for example, an environmental assessment approval. In some cases, these approvals will be obtained after the Board issues a leave to construct approval. It is possible that conditions attached to these approvals may result in material changes to the project that was reviewed by the Board (for example, a routing change or the imposition of additional costs that were not known to the Board). Under such circumstances, an applicant will be required to satisfy the Board that the project is still in the public interest.

4.3 Applicant and Project Types

In all electricity leave to construct applications under section 92(1), the Board considers the interests of consumers with respect to prices and the reliability and quality of electricity service, and, where applicable and in a manner consistent with the policies of the Government of Ontario, the promotion of the use of renewable energy sources."

The filing requirements differ depending on the type of applicant and project.

Applicants can be rate regulated, such as licensed transmitters that provide transmission services to third parties at Board-approved rates, or non-rate regulated, such as an owner of a large industrial plant or a generation facility that does not provide transmission services to third parties.

Rate-regulated applicants

There is an onus on rate-regulated entities whose revenues are derived from ratepayers to justify before the Board all expenditures on transmission facilities.

A rate-regulated transmitter applying for a leave to construct for a proposed project must provide all the minimum filing requirements with the application, whether or not the project has been included in a capital budget that has been approved in a rate hearing.

Rate-regulated transmitters and distributors applying for transmission connection projects are subject to additional requirements as set out in the Transmission System Code ("TSC") in the application to the Board.

Non Rate-regulated Applicants

Most of the projects proposed by non rate-regulated applicants are designed to connect generation or load sites or plants to the existing IESO controlled grid. The financial risk of constructing new transmission facilities lies with the owners and shareholders of the company, and not with rate payers. As rate payer money is not involved, these applicants generally do not need to justify their expenditures on their own transmission facilities to the Board. However, it should be noted that in certain circumstances these owners and shareholders may be required by the Board to share some or all of the costs associated with the Network Reinforcement, as set out in Section 6.3 of the TSC. In that case the Board will want to ensure that the shared costs are appropriately assigned.

Section 6.3 of the TSC sets out how cost sharing will need to be justified. Transmitters and distributors applying for transmission connection projects must include additional information as set out in the TSC in their applications to the Board, such as the calculation of any capital contribution, and the relevant annual connection rate revenues over the applicable evaluation period if the costs are not recoverable in connection rate revenues.

Distribution Projects

Section 92 also applies for distributors' projects involving transformation connection projects (e.g. a transformer station transforming from above 50 kV to below 50 kV), if the transmission line tap is more than 2 km in length. Facilities with voltages which are above 50kV and with line connections greater than 2km in length and which are or might be "deemed distribution" facilities are also subject to Section 92.

4.4 Filing Requirements for Projects under Section 92

The analysis of public interest implications may vary depending on the Applicant (rate-regulated or non rate-regulated) and type of transmission project being reviewed. The following minimum filing requirements apply to projects in a leave to construct proceeding. The exhibit designation is a suggestion and is not mandatory.

Exhibit A: Index

An index table listing exhibit numbers, tabs and schedules, and each of their contents shall be provided.

Exhibit B: The Application

1. Administrative

This section should include the formal signed application, which must include the following:

- the name of the applicant and partnerships involved in the application;
- the authorized representative of the applicant, phone, e-mail, fax and delivery address;
- an outline of the business of the applicant and parties in the application;
- an explanation of the purpose of the project for which leave to construct is being sought ;
- the financial structuring for the project, as necessary;
- a concise description of the routing and location of the project, including the affected municipalities and regions;
- a description of project components and their locations, activities, and related undertakings;
- the rationale for selecting the proposed project as opposed to any for alternatives considered
- an explanation of how the project is in the public interest, as defined by section 96(2) of the Act; and,
- the project schedule.

2. Project Overview Documents

The evidence in this section provides the background and a summary of the application, and assists the Board in drafting a Notice of Hearing for potential interested parties. This must include:

- a detailed description of location of the project and its components;
- maps (1:50,000 or larger) showing: the route, facility sites and any proposed ancillary facilities;

- the location of project components and related undertakings;
- line drawings of the proposed facility, showing supply connection(s) to the proposed facility and delivery facilities from the proposed facility to any adjacent transmission and/or distribution system(s); and
- the nominal rating of the main components of the project, including the transformers.

3. Need for the Project

In leave to construct applications, the Board's consideration is limited to the interests of consumers with respect to prices and the reliability and quality of electricity service and, where applicable and in a manner consistent with the policies of the Government of Ontario, the promotion of the use of renewable energy sources. This is mandated by section 96(2) of the Act, and the Board does not have the power to consider broader issues. The Board's consideration of the "need" for a project, therefore, can relate only to matters described in section 96(2).

Project justification delineates the responsibilities and necessary evidentiary components required for the project review. The responsibility for the provision of all evidence for the entire case rests with the applicant.

The applicant's evidence in support of the need for the project is required to be submitted and can be supported as necessary by evidence of the Independent Electricity System Operation ("IESO"), the transmitter, and/or the Ontario Power Authority: ("OPA"):

Where the Board has already considered aspects of the "price" consideration through a rates proceeding the applicant must still provide with their application:

- a description of the need for the project;
- a detailed reference to those approvals for any projects forming part of an approved plan or rate order; and,
- the reasons given for the inclusion of the project in those proceedings.

Classification of Project Need for Rate-regulated Transmitters:

This section relates to additional information required to be provided by rate-regulated Transmitters. Project Categorization, Classification and Justification assist in determining the need for the project. The categorization and classification are considered in a matrix as shown:

<table>
<tr><th colspan="4">PROJECT NEED</th></tr>
<tr><th colspan="2" rowspan="2"></th><th colspan="2">PROJECT Categorization</th></tr>
<tr><th>Non-discretionary</th><th>Discretionary</th></tr>
<tr><td rowspan="3">PROJECT Classification</td><td>Development</td><td></td><td></td></tr>
<tr><td>Connection</td><td></td><td></td></tr>
<tr><td>Sustainment</td><td></td><td></td></tr>
</table>

The classification and categorization is discussed in further detail here.

a) Project Classification

Project Classification is the classification of a project into one of three project classes:

- **Development projects** are those for providing:
  - an adequate supply capacity and/or maintaining an acceptable or prescribed level of customer or system reliability for load growth meeting increased stresses on the system; or
  - enhancing system efficiency such as minimizing congestion on the transmission system and reducing system losses.

- **Connection projects** are those for providing connection of a load or generation customer or group of customers to the transmission system.

- **Sustainment projects** are those for maintaining the performance of the transmission network at its current standard or replacing end-of-life facilities on a "like for like" basis.

It is acknowledged that projects can have elements of development, connection, or sustainment. In these cases, the applicant should identify the proportional make-up of the project, and then classify the project based on the predominant driver.

An investment in the Network may be required in any of these three project classifications. Network facilities are comprised of network stations and the transmission lines connecting them.

b) Project Categorization

The categorization stage identifies the project need as:

- **Non-discretionary** – a "must do" project, the need for which is determined beyond the control of the applicant ("Non-discretionary"), or
- **Discretionary** – the need is determined at the discretion of the applicant ("Discretionary").

The purpose of project categorization is to distinguish whether the project need is **beyond** the control of the ("Non-discretionary") or **at the discretion** of the Applicant ("Discretionary").

Non-discretionary projects may be triggered or determined by such things as:

- mandatory requirement to satisfy obligations specified by regulatory organizations including NPCC/NERC (the designated ERO in the future) or by the IESO;
- a need to connect new load (of a distributor or large user) or new generation (connection);
- a need to address equipment loading or voltage/short circuit stresses when their rated capacities are exceeded;
- projects identified in a Board or provincial government approved plan;
- projects that are required to achieve provincial government objectives that are prescribed in governmental directives or regulations; and
- a need to comply with direction from the Ontario Energy Board in the event it is determined that the transmission system's reliability is at risk.

Discretionary projects are proposed by the applicant to enhance the transmission system performance, benefiting its users. Projects in this category may include:

- projects to reduce transmission system losses;
- projects to reduce congestion;
- projects to build a new or enhance an existing interconnection to increase generation reserve margin within the IESO-controlled grid, beyond the minimum level required;
- projects to enhance reliability beyond a minimum standard; and
- projects which add flexibility to the operation and maintenance of the transmission system.

4. Evidence in Support of Need

The reasons that a project is necessary must be identified. The basic form for such evidence should be cost-benefit analyses, if applicable, of various options. The Board expects that Applicants will present:

- the preferred option (i.e. the proposed project); and
- alternative options.

It should be recognized, however, that the Board will either approve or not approve the proposed project (i.e. the preferred option). It will not choose a solution from among the alternative options. The applicant should present the smallest number of alternatives consistent with conveying to the Board the major solution concepts available to meet the same objectives that the preferred option meets.

When providing evidence on the need for the applied-for project, support may arise from a comparison with alternative possible projects. Where a proposed project is best compared to other viable transmission alternatives, the comparison should include "doing nothing".

Where the applicant lists the benefits of a leave to construct project as avoiding non-transmission alternatives such as a peaking generation facility or a "must run" generation requirement, it is helpful for the applicant to include corroborative evidence from the IESO or the OPA regarding the Applicant's quantitative evaluation of such a benefit. In any event, this evidence is required to support the need for the project.

The applicant is expected to also compare the alternatives versus the preferred option along various risk factors including, but not limited to:

- financial risk to the applicant;
- inherent technical risks;
- estimation accuracy risks; and
- any other critical risk that may impact the business case supporting the proposed project.

If the proposed project alternatives are expected to have significant qualitative benefits that cannot reasonably be quantified, evidence about these qualitative benefits should be provided. These benefits may be taken into account in ranking the alternatives. Incorporating qualitative criteria may result in a different ranking of projects compared to the ranking based on quantitative benefits and costs alone. For example, a project may be compared on the basis of its degree of disruption to property owners (least, more and most disruptive).

In addition to the evidence regarding the need for the project, the Applicant must address how it proposes to accomplish the project including the identification of relevant options.

For connection projects, in addition to the cost benefit analysis, the applicant must supply specific information on the nature and magnitude of the network impacts. Certain connection projects may require network reinforcement in order to proceed. A description of the additional information requirements in such cases is provided in Appendix 4 -A to this Chapter. Some of these requirements could affect an evaluation of projects and this should be taken into account.

Where an applicant attributes to a proposed project market efficiency benefits such as lower energy market prices, congestion reduction, or transmission loss reduction, the evidence submitted must include quantification of each of the market efficiency benefits listed for that proposed project.

Evidence of Need in Non-discretionary Projects

In the case of a non-discretionary project, the preferred option should establish that it is a better project than the alternatives. The applicant need not include “doing nothing” as an alternative since this alternative would not meet the need. One way for a rate-regulated applicant to demonstrate that a preferred option is the best option is to show that it has the highest net present value as compared to the other viable alternatives. However, this net present value need not be shown to be greater than zero. In contrast, in the case of a discretionary project, “doing nothing” would count as a viable option.

External Need Factors

In some cases, a discretionary or non-discretionary project’s need is driven by factors external to the applicant, such as the need to satisfy an IESO requirement or to serve an incremental customer load. Where the applicant identifies a customer or agency (such as the IESO or the OPA) as the driver behind a project:

- It is the Applicant’s responsibility to include evidence from that customer or agency as part of the evidence in the application.
- The customer or agency must be prepared to provide witnesses as needed to support the filed evidence if an oral hearing is held.
- It is not sufficient for the applicant to state that the customer or agency has established the need for the project; the Board must be able to test that assertion.
- The Board expects the applicant to work with that external party in the development of the required evidence. The external party will often be the IESO and/or the OPA, although the additional evidentiary requirement could apply to any external party on whom the applicant has relied for the justification of the need for the project.

The evidence may include:

- written material prepared by the customer or agency specifically addressing the proposed project, and,
- a list identifying the key driving factors of the evidence justifying the project need, and the party (e.g. the applicant, the IESO, or the OPA) which has prepared the evidence to justify a given key driving factor.

5. Project Shared Costs

Where there are costs which are shared between rate regulated and non rate-regulated parties, proponents must provide details of project costs to the rate-regulated party. Applicants should provide details covering:

- labour - including a breakdown by facility installations;
- materials - including a breakdown of all facility costs;
- cost of similar projects constructed by the applicant or by other entities for baseline cost comparisons covering:
    - in-service year of the comparator project, and
    - similarities and differences in terms of voltage level, type of towers, type of terrain, etc.
- acquisition of land use rights, and land acquisition including permanent and working easements, survey and appraisals, legal fees, crop and damage compensation;
- direct and indirect overheads broken down by facility installation; and,
- allowance for funds used during construction (“AFUDC”).

6. Transmission Rate Impact Assessment

The Board requires information relating to the rate impacts anticipated from transmission investments. Information should cover the short-term impacts as well as long-term impacts of the proposed project.

7. Establishment of Deferral Accounts

The Board would consider applications by licensed transmitters requesting that the Board include with its grant for leave to construct, the establishment of a deferral account (under the Uniform System of Accounts) to track the project construction costs and that such accounts would be reviewed for prudence and inclusion in rate base in a future rate proceeding.

Exhibit C: Project Planning

The applicant must provide the Board with time estimates for construction and service dates, including:

- the critical path and time frame for the completion of construction and operational start-up of the proposed facilities;
- any aspects of the start-up of operation relative to the introduction of the new or

additional market demands on the transmission system;

- the estimated schedule (time of year and duration) for each of the major construction activities and the implications of critical constraints such as:
  - delay in start of construction due to failure to obtain timely approvals;
  - prolonged adverse weather conditions;
  - availability of qualified contractors and/or skilled trades persons;
  - construction windows due to environmental constraints; and,
  - the projected and contractual in-service date for the facilities.

Exhibit D: Project Details:

This section of the application must provide detailed information on the project, focussing on identifying project design features and procedures that will ensure the safe and reliable operation of the proposed facilities. These design specifications should demonstrate compliance with the technical requirements as specified in the TSC.

The route of the line is critical because the Board will only provide leave to construct for a specific route. Any material deviations to the approved route following Board approval will invalidate the leave to construct.

This exhibit should include:

- Descriptions of the physical design, including:
  - a section by section description of the physical form of the line;
  - transmission line details, including conductor type, ratings;
  - transmission structure description including the variety of towers;
  - transmission cable burial information and cross-section; and
  - transformer and switching stations
- Maps indicating:
  - the route of the line and the Lot number and Concession number through or adjacent to which the line runs;
  - the plan of each section of the transmission line in relation to the description and indicating clearances to the land profile or, where buried, in relation to the surface; and
  - the right-of-way dimensions and an indication of where the route crosses privately owned land.

Exhibit E: Design Specifications and Operational Data

Operational details:

The application must provide the following details on the planned operation of the transmission line including:

- the control stations
- monitoring and metering locations

Codes, Standards and Regulations:

The application must provide a description of any applicable codes, standards, and regulations that are applicable to the project. It must also provide engineering details with respect to any special design features, which may influence the construction and in-service schedule and to demonstrate that the proposed transmission facilities will be safe and reliable. Specifically, a table should be provided which indicates:

- a list of any documents, including permits, licences and approvals from other agencies which must be received before the project can be implemented;
- the reason the document is required; and
- the location of the various physical sections and components of the project.

Exhibit F: Land Matters

The application must include accurate documentation that demonstrates compliance with legislative requirements and respects the rights of affected parties, including:

- land easements required
- land rights, and
- the land acquisition process.

A description of the land area required including:

- the width(s) of any right-of-way required on new and/or existing easements;
- the location and ownership of land with existing easements and of any new easements or land use rights that will be required; and
- the need and amount of additional temporary working rights required at designated locations such as crossings of rivers, roads, railways, drains and other facilities.

A description of the land rights required must be provided including:

- the type of land rights proposed to be acquired for the project and related facilities (e.g. permanent easement, fee simple);
- the nature and relative proportions of land ownership along the proposed route (i.e., freehold, Crown or public lands); and,
- where no new land rights are required, a description of the existing land rights that allow for the project.

A description of the land acquisition process including:

- identification of the properties and the property owners and/or tenants affected by the proposed construction (landowners line list);
- the extent of notification to landowners regarding the routing of the new facility, the environmental assessment and the facility application;
- the applicant's plan for acquiring new easements or for amending existing easements; and the progress achieved to date with affected landowners, any concerns, or objections registered by affected landowners and municipalities with respect to the proposed construction, and the resolution of these concerns.

A copy of, or a reference for, each of the following forms must be submitted where applicable and where an up-to-date copy is not already on file with the Board:

- the option for easement form;
- the working rights agreement form;
- the easement agreement form;
- the damage release form; and,
- a copy of any correspondence with affected landowners outlining changes in company policy with respect to land acquisitions.

Exhibit G: Community and Stakeholder Consultation

The Board expects applicants will consider stakeholder consultation for all projects. Applicants are responsible for justifying the extent of consultation carried out for each application. The following information should be provided within the application:

- principles and goals of the consultation program;
- design details of the consultation program; and,

- the results of the consultation carried out, including how public input influenced the design, construction, or operation of the project; or,
- an explanation if no consultation was pursued.

As a result of the limits on the Board's jurisdiction imposed by subsection 96(2), the Board does not itself consider issues relating to the Crown's duty to consult with Aboriginal peoples in section 92 applications[8]. However, applicants should be aware that the proposed project may well give rise to duty to consult issues that will be dealt with in other forums (for example, the environmental assessment).

Exhibit H: System Impact Assessment

The IESO Connection Assessment and Approval process identifies the detailed procedures to be followed by applicants who wish to connect or modify a connection to the IESO-administered grid. The IESO evaluates the design of the project and its impact on integrated power system reliability, and identifies any transmission facility enhancements required. IESO requirements must be fulfilled in addition to those listed here.

Exhibit I: Customer Impact Assessment

The Applicant, including a rate-regulated transmitter if it is the Applicant, is required to include in its evidence a Customer Impact Assessment (CIA) report, as required by the TSC.

The CIA report is to be completed by the rate-regulated transmitter to which the Applicant's transmission facilities are connected. A transmitter shall carry out a CIA for any proposed new or modified connection where:

- the connection is one for which the IESO's connection assessment and approval process requires a system impact assessment; or
- the transmitter determines that the connection may have an impact on existing customers.

A transmitter may decide not to carry out a CIA for any proposed new connection or modification that is not subject to a system impact assessment. In such a case, the transmitter would notify existing customers in the vicinity, advising them of the proposed new connection or modification and of the transmitter's decision not to carry out a CIA on the basis that no customer impact is expected.

[8] See, for example, the Board's Decision on Questions of Jurisdiction and Procedural Order No. 4 in EB-2009-0120, issued November 18, 2009.

A transmitter would provide each affected customer with a new available fault current level at its delivery point(s). This would allow each customer to take, at its own expense, action to upgrade its facilities as may be required to accommodate the new available fault current level up to the maximum allowable fault levels set out in Appendix 2 of the TSC.

Appendix 4-A

Connection Projects Requiring Network Reinforcement

For review of connection projects the Board requires submission of evidence to cover various aspects including:

- Transmission System Impact and Network Reinforcement;
- Cost Responsibility for Network Reinforcement; and
- Implementation of Required Network Upgrades

Transmission System Impact and Network Reinforcement

The applicant must supply information on the nature and magnitude of any impact of the proposed connection facility on the transmission system. Normally the IESO addresses and provides high level assessment of such impacts in the System Impact Assessment report performed by the IESO as set out in the IESO's Connection Assessment and Approval process.

This information will not on its own be determinative of the decision on leave to construct in these applications as the cost responsibility of line connection investments are addressed fully in the Transmission System Code (TSC) and the applicant is responsible for demonstrating compliance with the TSC.

However, the Board may determine that a transmitter(s) needs to apply for a leave to construct to make the required network upgrades triggered by the proposed connection project. If a leave to construct is necessary, the Board may wish to invite the transmitter(s) to make the needed applications at the same time, or immediately following, the application of the connecting customer.

The nature and magnitude of other network impacts resulting from the proposed investment must be identified e.g. changes in generation dispatch and transmission line losses.

Cost Responsibility for Network Reinforcement

Section 6.3.5 of the TSC states that "A transmitter shall not require any customer to make a capital contribution for the construction of or modifications to the transmitter's network facilities that may be required to accommodate a new or modified connection. If exceptional circumstances exist so as to reasonably require a customer to make a capital contribution for network construction or modifications, the transmitter or any other interested person may apply to the Board for direction."

Transmitters and other interested parties may apply to the Board for direction on the existence of “exceptional circumstances” requiring the connecting customer to make a capital contribution for network investments triggered by their proposed line connection. The onus is on the transmitter and other interested parties to establish to the Board’s satisfaction that “exceptional circumstances” exist.

Implementation of Required Network Upgrades

When the proposed investment project necessitates network upgrades to comply with the TSC and other industry standards and codes, the nature, magnitude and impact of the necessary upgrades must be identified e.g. changes in generation dispatch and transmission line losses).

A key objective of the OEB in these contexts is early identification of the magnitude of any upstream network impacts resulting from a connection investment. This early identification will enable the OEB to determine if relevant rate-regulated transmitters should be invited to pursue leave to construct applications. A related objective is to enable any person to make application to the Board under section 6.3.5 of the TSC for a finding that exceptional circumstances apply, and that the connection proponent should therefore bear some portion of the cost responsibility for the resulting network upgrades that are required.

Chapter 5 Prior to the approval of an Integrated Power System Plan: Filing requirements for the approval of a capital budget for a transmission project in a rate application or for the approval of projects under section 92 of the OEB Act

The information previously in this chapter has been consolidated into Chapter 4.

Ontario Energy Board

Commission de l'énergie de l'Ontario

Ontario Energy Board

Chapter 5 of the Filing Requirements For Electricity Transmission and Distribution Applications

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Chapter 6 of the Filing Requirements For Electricity Transmission and Distribution Applications

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EB-2006-0327

Ontario Energy Board

Filing Requirements for Service Area Amendment Applications

To be included as Chapter 7
of the Filing Requirements for Electricity
Transmission and Distribution Applications

(March 12, 2007)

CHAPTER 7: FILING REQUIREMENTS FOR SERVICE AREA AMENDMENT APPLICATIONS

TABLE OF CONTENTS

This chapter provides information to guide distributors in filing applications that involve service area amendments (“SAA”).

A SAA is an amendment to Schedule 1 of a distributor’s licence. Schedule 1 of a distributor's licence is the part of the licence that defines the distributor’s service area. Section 74(1) of the Act allows the Board to amend distributors’ licences where the amendment is in the public interest.

The development of SAA filing requirements is guided by the Board’s objectives in electricity namely, economic efficiency, consumer protection and the maintenance of a financially viable electricity industry. The filing requirements are also based on the general principles articulated in the Board’s Decision on the Combined Service Area Amendments Proceeding (“RP-2003-0044”).

In RP-2003-0044, the Board articulated certain principles on consumer protection and economic efficiency in relation to SAAs. One such principle is that economic efficiency and the protection of consumer interests will be achieved through the rational optimization of existing distribution systems.

The RP-2003-0044 decision also provided the Board's view that applications that are consented to by the contiguous distributors and individual customers involved can be processed expeditiously. While all SAA applications would need to address the principles outlined in the RP-2003-0044 decision (i.e., economic efficiency, impacts on distributors and their customers, and customer preference), the Board stated that the level of detail required for consent applications would be less than that required for contested applications.

The information in sections 7.1 to 7.4 must be provided for all SAA applications. The information requested under section 7.5 must be provided for contested SAA applications (i.e., applications where the applicant has not been able to obtain the consent of all affected parties).

For the purposes of these filing requirements, it is assumed that the applicant is a distributor who requires a service area amendment to its licence. Some of the information required by these filing requirements may be third-party information that the applicant does not have in its possession. In such cases, the applicant will be expected to use its best efforts to obtain the third-party information and comply with all provisions of these filing requirements. The Board may continue to process the SAA application notwithstanding the fact that the third-party information is not included with the filed SAA application. However, the Board will not determine the SAA application until all of the required information is filed during the course of the proceeding regardless of whether the information is provided by the applicant, the incumbent distributor (i.e., the distributor that currently has the region that is the subject of the SAA application in its service area), the customer, or other relevant third party. In appropriate cases, the Board may direct the relevant third parties to file the information required by the Board.

The filing requirements set out in this chapter do not limit the discretion of the Board in terms of what information and evidence it may wish to see during the course of a proceeding. The filing requirements set out in this chapter are also not intended to limit the applicants in terms of what information they may wish to file in addition to the information required by this chapter.

7.1 Basic Facts

The information in this section is required to provide the Board with basic information about the application and an understanding of the details of the proposed SAA.

General

7.1.1 Provide the contact information for each of the following persons:

- (a) the applicant;
- (b) the incumbent distributor;
- (c) every affected customer, landowner, and developer in the area that is the subject of the SAA application;
- (d) any alternate distributor other than the applicant and the incumbent distributor, if there are any alternate distributors bordering on the area that is the subject of the SAA application; and
- (e) any representative of the persons listed above including, but not limited to, a legal representative.

Contact information includes the name, postal address, telephone number, and, where available, the email address and fax number of the persons listed above.

7.1.2 Indicate the reasons why this amendment should occur and identify any load transfers eliminated by the proposed SAA.

Description of Proposed Service Area

7.1.3 Provide a detailed description of the lands that are the subject of the SAA application. For SAA applications dealing with individual customers, the description of the lands should include the lot number, the concession number, and the municipal address of the lands. The address should include the street number, municipality and/or county, and postal code of the lands. For SAA applications dealing with general expansion areas, the description of the lands should include the lot number and the concession number of the lands, if available, as well as a clear description of the boundaries of the area (including relevant geographical and geophysical features).

7.1.4 Provide one or more maps or diagrams of the area that is the subject of the SAA application. The maps or diagrams must identify the following information:

a) the borders of the applicant's service area;
b) the borders of the incumbent distributor's service area;
c) the borders of any alternate distributor's service area, if applicable;
d) the territory surrounding the area for which the applicant is making the SAA application;
e) the geographical and geophysical features of the area including, but not limited to, rivers and lakes, property borders, roads, and major public facilities; and
f) the existing facilities supplying the area that is the subject of the SAA application, if applicable, as well as the proposed facilities which will be utilized by the applicant to supply the area that is the subject of the SAA application (Note: if the proposed facilities will be utilized to also provide for expansion of load in the area that is the subject of the SAA application, identify that as well).

Distribution Infrastructure In and Around the Proposed Amendment Area

7.1.5 Provide a description of the proposed type of physical connection (i.e., individual customer; residential subdivision, commercial or industrial development, or general service area expansion).

7.1.6 Provide a description of the applicant's plans, if any, for similar expansions in lands adjacent to the area that is the subject of the SAA application. Provide a map or diagram showing the lands where expansions are planned in relation to the area that is the subject of the SAA application.

7.2 Efficient Rationalization of the Distribution System

The proposed SAA will be evaluated in terms of rational and efficient service area realignment. This evaluation will be undertaken from the perspective of economic (cost) efficiency as well as engineering (technical) efficiency.

Applicants must demonstrate how the proposed SAA optimizes the use of existing infrastructure. In addition, applicants must indicate the long term impacts of the proposed SAA on reliability in the area to be served and on the ability of the system to meet growth potential in the area. Even if the proposed SAA does not represent the lowest cost to any particular party, the proposed SAA may promote economic efficiency if it represents the most effective use of existing resources and reflects the lowest long run economic cost of service to all parties.

7.2.1 In light of the above, provide a comparison of the economic and engineering efficiency for the applicant and the incumbent distributor to serve the area that is the subject of the SAA application. The comparison must include the following:

a) the location of the point of delivery and the point of connection;

b) the proximity of the proposed connection to an existing, well-developed electricity distribution system;

c) the fully allocated connection costs for supplying the customer (i.e., individual customers or developers) unless the applicant and the incumbent distributor provide a reason why providing the fully allocated connection costs is unnecessary for the proposed SAA (Note: the Board will determine if the reason provided is acceptable).

d) the amount of any capital contribution required from the customer;

e) the costs for stranded equipment (i.e., lines, cables, and transformers) that would need to be de-energized or removed;

f) information on whether the proposed SAA enhances, or at a minimum doses not decrease, the reliability of the infrastructure in the area that is the subject of the SAA application and in regions adjacent to the area that is the subject of the SAA application over the long term;

g) information on whether the proposed infrastructure will provide for cost-efficient expansion if there is growth potential in the area that is the subject of the SAA application and in regions adjacent to the area that is the subject of the SAA application; and

h) information on whether the proposed infrastructure will provide for cost-efficient improvements and upgrades in the area that is the subject of the SAA application and in regions adjacent to the area that is the subject of the SAA application.

7.3 Impacts Arising from the Proposed Amendment

Description of Impacts

7.3.1 Identify any affected customers or landowners.

7.3.2 Provide a description of any impacts on costs, rates, service quality, and reliability for customers **in** the area that is the subject of the SAA application that arise as a result of the proposed SAA. If an assessment of service quality and reliability impacts cannot be provided, explain why.

7.3.3 Provide a description of any impacts on costs, rates, service quality, and reliability for customers of any distributor **outside** the area that is the subject of the SAA application that arise as a result of the proposed SAA. If an assessment of service quality and reliability impacts cannot be provided, explain why.

7.3.4 Provide a description of the impacts on each distributor involved in the proposed SAA. If these impacts have already been described elsewhere in the application, providing cross-references is acceptable.

7.3.5 Provide a description of any assets which may be stranded or become redundant if the proposed SAA is granted.

7.3.6 Identify any assets that are proposed to be transferred to or from the applicant. If an asset transfer is required, has the relevant application been filed in accordance with section 86 of the Act? If not, indicate when the applicant will be filing the relevant section 86 application.

7.3.7 Identify any customers that are proposed to be transferred to or from the applicant.

7.3.8 Provide a description of any existing load transfers or retail points of supply that will be eliminated.

7.3.9 Identify any new load transfers or retail points of supply that will be created as a result of the proposed SAA. If a new load transfer will be created, has the applicant requested leave of the Board in accordance with section 6.5.5 of the Distribution System Code ("DSC")? If not, indicate when the applicant will be filing its request for leave under section 6.5.5 of the DSC with the Board. If a new retail point of supply will be created, does the host distributor (i.e., the distributor who provides electricity to an embedded distributor) have an applicable Board approved rate? If not, indicate when the host distributor will be filing an application for the applicable rate.

Evidence of Consideration and Mitigation of Impacts

7.3.10 Provide written confirmation by the applicant that all affected persons have been provided with specific and factual information about the proposed SAA. As part of the written confirmation, the applicant must include details of any communications or consultations that may have occurred between distributors regarding the proposed SAA.

7.3.11 Provide a letter from the incumbent distributor in which the incumbent distributor indicates that it consents to the application.

7.3.12 Provide a written response from all affected customers, developers, and landowners consenting to the application, if applicable.

7.3.13 Provide evidence of attempts to mitigate impacts where customer and/or asset transfers are involved (i.e., customer rate smoothing or mitigation, and compensation for any stranded assets).

7.4 Customer Preference

The Board, in the RP-2003-0044 decision, stated that customer preference is an important, but not overriding consideration when assessing the merits of an SAA.

7.4.1 An applicant who brings forward an application where customer choice may be a factor must provide a written statement signed by the customer (which includes landowners and developers) indicating the customer's preference.

7.5 Additional Information Requirements for Contested Applications

If there is no agreement among affected persons regarding the proposed SAA, the applicant must file the additional information set out below.

7.5.1 If the application was initiated due to an interest in service by a customer, landowner, or developer, evidence that the incumbent distributor was provided an opportunity to make an offer to connect that customer, landowner, or developer.

7.5.2 Evidence that the customer, landowner, or developer had the opportunity to obtain an offer to connect from the applicant and any alternate distributor bordering on the area that is the subject of the SAA application.

7.5.3 Actual copies of, as well as a summary of, the offer(s) to connect documentation (including any associated financial evaluations carried out in accordance with Appendix B of the Distribution System Code). The financial evaluations should indicate costs associated with the connection including, but not limited to, on-site capital, capital required to extend the distribution system to the customer location, incremental up-stream capital investment required to serve the load, the present value of incremental OM&A costs and incremental taxes as well as the expected incremental revenue, the amount of revenue shortfall, and the capital contribution requested.

7.5.4 If there are competing offers to connect, a comparison of the competing offers to connect the customer, landowner, or developer.

7.5.5 A detailed comparison of the new or upgraded electrical infrastructure necessary for each distributor to serve the area that is the subject of the SAA application, including any specific proposed connections.

7.5.6 Outage statistics or, if outage statistics are not available, any other information regarding the reliability of the existing line(s) of each distributor that are proposed to supply the area that is the subject of the SAA application.

7.5.7 Quantitative evidence of quality and reliability of service for each distributor for similar customers in comparable locations and densities to the area that is the subject of the SAA application.

Report of the Board
Renewed Regulatory Framework for Electricity Distributors:
A Performance Based Approach

Ontario Energy Board

Report of the Board

Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach

October 18, 2012

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1 Introduction

The Ontario Energy Board regulates the rates of the 77 local electricity distributors that operate Ontario's local electricity delivery networks. These networks are essential to the seamless delivery of electricity from generators to end users. The cost of distributing electricity represents approximately 20% to 25% of the total electricity bill. Revenues collected from customers contribute to the ongoing operation and maintenance of the system as well as its expansion and modernization. Ontario's electricity distributors represent significant capital investments, with total assets of approximately $17 billion, and new investment of $1.9 billion in 2011. And while all distributors perform a similar service, their investment needs vary over time. Ontario's energy sector is evolving, as are the expectations of customers and the obligations placed on distributors as a result. The Board believes that our approach to regulation needs to evolve along with the sector.

The Board needs to regulate the industry in a way that serves present and future customers, and that better aligns the interests of customers and distributors while continuing to support the achievement of public policy objectives, and that places a greater focus on delivering value for money. A number of factors have prompted the Board's work on a renewed regulatory framework: government policy, aging infrastructure, customer concerns regarding rate increases, the increased maturity of the industry, and a need to harmonize and consolidate Board policies related to planning and rate setting.

The Board's renewed regulatory framework for electricity is designed to support the cost-effective planning and operation of the electricity distribution network – a network that is efficient, reliable, sustainable, and provides value for customers. Through taking a longer term view, the new framework will provide an appropriate alignment between a sustainable, financially viable electricity sector and the expectations of customers for reliable service at a reasonable price. The performance-based approach described in this Report is an important step in the continued evolution of electricity regulation in Ontario.

In developing the policies set out in this Report, the Board has been informed by, and has benefitted greatly from, extensive consultation and dialogue with stakeholders representing a broad range of interests and perspectives. The materials generated for and through this consultation provide useful background and context for the issues discussed in this Report, as well as a detailed record of stakeholder comments on those issues. Many of these materials are listed in Appendix A, and all are readily available on the Board's website.

The renewed regulatory framework is a comprehensive performance-based approach to regulation that is based on the achievement of outcomes that ensure that Ontario's electricity system provides value for money for customers. The Board believes that emphasizing results rather than activities, will better respond to customer preferences, enhance distributor productivity and promote innovation. The Board has concluded that the following outcomes are appropriate for the distributors:

Customer Focus: services are provided in a manner that responds to identified customer preferences;

Operational Effectiveness: continuous improvement in productivity and cost performance is achieved; and utilities deliver on system reliability and quality objectives;

Public Policy Responsiveness: utilities deliver on obligations mandated by government (e.g., in legislation and in regulatory requirements imposed further to Ministerial directives to the Board); and

Financial Performance: financial viability is maintained; and savings from operational effectiveness are sustainable.

The Board has developed a set of related policies to facilitate the achievement of these performance outcomes. The Board remains committed to continuous improvement within the electricity sector, The Board's policies for setting distributor rates as outlined below are supported by fundamental principles of good asset management; coordinated, long term planning; and a common set of performance, including productivity expectations.

The following are the three main policies:

- Rate-setting: There will be three rate-setting methods: 4th Generation Incentive Rate-setting (suitable for most distributors), Custom Incentive Rate-setting (suitable for those distributors with large or highly variable capital requirements), and the Annual Incentive Rate-setting Index (suitable for distributors with limited incremental capital requirements). These rate-setting methods will provide choices suitable for distributors with varying capital requirements, while ensuring continued productivity improvement. Rate-setting is discussed in Chapter 2.

- Planning: Distributors will be required to file 5-year capital plans to support their rate applications. Planning will be integrated in order to pace and prioritize capital expenditures, including smart grid investments. Regional infrastructure planning will be undertaken where warranted. The Board will also propose amendments to the Transmission System Code to facilitate the execution of regional plans. Planning is discussed in Chapter 3.

- Measuring Performance: The Board will develop standards, and measures that will link directly to the performance outcomes listed above. Using a scorecard approach distributors will be required to report annually on their key performance outcomes. Performance measures and monitoring are discussed in Chapter 4.

In developing the policies in this Report, the Board has been guided by its objectives in relation to electricity, as listed in section 1(1) of the *Ontario Energy Board Act, 1998* (the "OEB Act"). These objectives are:

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

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

3. To promote electricity conservation and demand management in a manner consistent with the policies of the Government of Ontario, including having regard to the consumer's economic circumstances.

4. To facilitate the implementation of a smart grid in Ontario.

5. To promote the use and generation of electricity from renewable energy sources in a manner consistent with the policies of the Government of Ontario, including the timely expansion or reinforcement of transmission systems and distribution systems to accommodate the connection of renewable energy generation facilities.

The first two objectives, the protection of consumer interests and the promotion of economic efficiency and cost effectiveness within a financially viable industry, are the foundation of the renewed regulatory framework. These objectives are reflected in the outcomes set out above and are the main principles of the distribution rate-setting and performance measurement policies. They are also key considerations in the emphasis on pacing and prioritization of capital investment embodied in the planning policy.

The remaining three objectives of the Board in relation to electricity are reflected in the policies regarding infrastructure planning. Steps toward achieving these public policy objectives in respect of conservation and demand management, smart grid implementation and the expansion or reinforcement of the system to facilitate renewable generation are incorporated into the planning policy.

With the exception of regional infrastructure planning and smart grid, which apply to both distributors and transmitters, the policies set out in this Report apply to distributors only at this time. In due course, the Board will provide further guidance regarding how the policies in this Report may be applied to transmitters.

Policies in relation to the conclusions set out in this Report will be largely implemented in time for the 2014 rate year. Specifically, the new instruments for all three rate setting methods will be available to those seeking to rebase rates effective May 1, 2014.

The Board is committed to monitoring and evaluating the effectiveness of its policies. It will do so by identifying desired policy outcomes and requiring annual monitoring and reporting to measure success against those outcomes. The Board will develop the policy evaluation framework for the renewed regulatory framework after further work has been completed in relation to the distributor performance “scorecard”. More information on this policy evaluation framework will be provided later.

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2 Electricity Distribution Rate-Setting

2.1 Background

The Board has employed incentive regulation ("IR"), including formula-based and cost-based rate-setting, since it began regulating the rates of electricity distributors in 2001. Under its current approach to IR, the Board uses one year forecasted cost and revenue information to determine a base revenue requirement and the "base" rates that are set to recover that revenue requirement. In subsequent years, those base rates are adjusted annually according to a Board-approved formula that includes components for inflation and the Board's expectations of efficiency and productivity gains.

The Board's current IR plan for distributors ("3rd Generation IR") was established in 2008.[1] The core of the 3rd Generation IR plan is an "inflation minus X-factor" price-cap form of rate adjustment mechanism, which is intended to incent innovation and efficiency. The X-factors for individual distributors consist of an empirically derived industry productivity trend and differentiated stretch factors. Benchmarking, based only on operations, maintenance and administration ("OM&A") cost data, provides the basis for the annual assignment of stretch factors to distributors.

2.2 Evolving the Board's Approach to Rate-setting

As noted in Chapter 1, the maintenance and modernization of electricity distribution infrastructure will continue to exert cost pressures on customers. The Board's approach to rate-setting must continue to support a sustainable, financially viable and reliable

[1] The Board's 3rd Generation IR policy approach is set out in the "Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors" dated July 14, 2008. A Supplemental Report of the Board setting out the Board's determination of the values for the productivity factor, the stretch factors, and the capital module materiality threshold for use in the 3rd Generation IR plan was issued on September 17, 2008; and on January 29, 2009, the Board issued its "Addendum to the Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors" which sets out the Board's determination on the model it would use to assign stretch factors to distributors.

electricity system. It must do so in a manner that is responsive to customers' concerns about affordability, by promoting increased efficiency which in turn can lower costs and provide for more predictable rates. It must also do so in a manner that better accommodates differing circumstances of distributors (for example, with respect to customer expectations, asset profile and investment needs) and facilitates the cost-effective and efficient achievement of expected performance outcomes. Finally, the rate regime must also recognize the inter-connected nature of the electricity system in Ontario, promote ongoing productivity improvements, encourage innovation, and support efficient regulation.

As part of the renewed regulatory framework consultation process, the Board issued a "straw man" model regulatory framework that identified at a high level certain potential changes to the Board's approach to rate-setting, including the pre-approval of multi-year plans, a focus on reliability, targeted rate-setting (treating OM&A and capital separately) to increase the pursuit of operating efficiencies, and greater flexibility in respect of the period between cost of service reviews.

Stakeholder Views

Stakeholder views on whether rate-setting should be targeted or comprehensive diverged significantly. Some distributors expressed strong support for targeted rate-setting. Those opposed argued that the capital and operating expenditures are too inter-related to be easily severed. Further, these stakeholders expressed concern that severing the two could create bias for one over the other resulting in sub-optimal investment, particularly in the absence of least-cost planning processes.

Stakeholder comment was generally in support of flexibility in the length of an IR term. Some stakeholders representing different business groups noted that aligning the IR plan term to match a 5-year planning horizon would be a sensible approach.

With respect to the current 3rd Generation IR plan, many stakeholders supported revising the inflation and productivity indices to better reflect circumstances faced by distributors in Ontario. Regarding the ICM some argued it is too restrictive while another commented it is sufficient because it is meant to be used in extraordinary circumstances rather than on a regular basis.

Many stakeholders commented on the need for flexibility in rate-setting to accommodate distributor differences, especially with respect to different capital spending needs. A menu approach – one that could include more than one type of rate-setting method (e.g., a simple index method and a multi-year approval-type method) – was identified by a few stakeholders as the preferred means of providing such flexibility. It was suggested that a distributor’s ability to access certain rate-setting options should be linked to the distributor’s benchmarked performance ranking.

Off-ramps and earnings sharing mechanisms were identified by some as necessary ratepayer protection mechanisms, particularly in longer term IR rate-setting.

The Board’s Conclusions

The Board continues to support a comprehensive approach to rate-setting, recognizing the interrelationship between capital expenditures and OM&A expenditures. Rate-setting that is comprehensive creates stronger and more balanced incentives and is more compatible with the Board’s implementation of an outcome-based framework.

Three alternative rate-setting methods will be available to distributors.

Each distributor may select the rate-setting method that best meets its needs and circumstances, and apply to the Board to have its rates set on that basis. This will provide greater flexibility to accommodate differences in the operations of distributors, some of which have capital programs that are expected to be significant and may include “lumpy” investments, and others of which have capital needs that are expected to be comparatively stable over a prolonged period of time.

The Board remains committed to the principles enunciated in its 3rd Generation IR report, and all three rate-setting methods are based on a multi-year IR mechanism. Each rate method will be supported by: the fundamental principles of good asset management; coordinated, longer-term optimized planning; a common set of performance expectations; and benchmarking. Rate applications will be supported by a five-year capital plan that includes consideration of regional infrastructure planning.

The Board believes that this more flexible approach to rate-setting will:

- enhance predictability necessary to facilitate planning and decision-making by customers and distributors;
- better align rate-setting with distributor planning horizons;
- facilitate the cost-effective and efficient implementation of distributor multi-year plans that have been developed to achieve the outcomes for customer service and cost performance; and
- help to manage the pace of rate increases for customers.

The Board’s rate-setting policy in this Report represents a further development of the approach adopted by the Board when it first established performance based regulation (“PBR”) for electricity distributors in its January 18, 2000 Decision with Reasons:

> … PBR is not just light-handed cost of service regulation. For the electricity distribution utilities in Ontario, PBR represents a fundamental shift from the historical cost of service regulation. It provides the utilities with incentive for behaviour which more closely resembles that of competitive, cost-minimizing, profit-maximizing companies. Customers and shareholders alike can gain from efficiency enhancing and cost-

> minimizing strategies that will ultimately yield lower rates with appropriate safeguards for service quality. Under PBR the regulated utility will be responsible for making its investments based on business conditions and the objectives of its shareholder within the constraints of the price cap, and subject to service quality standards set by the Board."[2]

Going into PBR, distribution rates are set based on a cost of service review. Subsequently, rates are adjusted based on changes to the input price index and the productivity and stretch factors set by the Board. PBR decouples the price (the distribution rate) that a distributor charges for its service from its cost. This is deliberate and is designed to incent the behaviours described by the Board in 2000. This approach provides the opportunity for distributors to earn, and potentially exceed, the allowed rate of return on equity. It is not necessary, nor would it be appropriate, for ratebase to be re-calibrated annually.

In implementing the new approach to rate-setting, the Board will use a rigorous performance reporting and monitoring process to ensure that, while distributors are responding to performance incentives, customer interests are being protected. As described in Chapter 4, a scorecard will be developed to measure distributor performance on four performance outcomes: customer focus, operational effectiveness, public policy responsiveness, and financial performance. One measure that will continue to be considered by the Board is annual earnings. The Board's policy in relation to the off-ramp, as set out in its July 14, 2008 EB-2007-0673 Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors, continues to be appropriate. Each rate-setting method will include a trigger mechanism with an annual return on equity ("ROE") dead band of ±300 basis points. When a distributor performs outside of this earnings dead band, a regulatory review may be initiated. The Board will continue to require consistent, meaningful and timely reporting to enable the Board to monitor utility performance and determine if the expected outcomes are being achieved. This approach will, in turn, allow the Board to take corrective action if required, including the possible termination of the distributor's rate-setting method and requiring the distributor to have its rates rebased. Customer

[2] Paragraph 2.0.14, p. 13, RP-1999-0034 Decision with Reasons, January 18, 2000

interests will also remain protected through regulatory processes that will continue to be open and transparent.

To ensure that the benefits from greater efficiency are appropriately shared throughout the rate-setting term between the distributor/shareholder and the distributor's customers, the expected benefits will be taken into account in establishing the rate adjustment mechanisms applicable to each rate method through the X factor.

With the introduction of these three rate-setting methods, the Board will review its existing rate-related policies for continued efficacy and to confirm whether and to what extent they can be integrated into any one or more of these rate-setting methods. The Board currently expects that existing policies will remain in place to support rate-setting in the future.

The key elements of the three rate-setting methods are set out in the following Table, and are described in greater detail below.

Table 1: Rate-Setting Overview - Elements of Three Methods

<table>
<tr><th colspan="2"></th><th>4th Generation IR</th><th>Custom IR</th><th>Annual IR Index</th></tr>
<tr><td colspan="5">Setting of Rates</td></tr>
<tr><td colspan="2">“Going in” Rates</td><td>Determined in single forward test-year cost of service review</td><td>Determined in multi-year application review</td><td>No cost of service review, existing rates adjusted by the Annual Adjustment Mechanism</td></tr>
<tr><td colspan="2">Form</td><td>Price Cap Index</td><td>Custom Index</td><td>Price Cap Index</td></tr>
<tr><td colspan="2">Coverage</td><td colspan="3">Comprehensive (i.e., Capital and OM&A)</td></tr>
<tr><td rowspan="2">Annual Adjustment Mechanism</td><td>Inflation</td><td>Composite Index</td><td rowspan="3">Distributor-specific rate trend for the plan term to be determined by the Board, informed by: (1) the distributor’s forecasts (revenue and costs, inflation, productivity); (2) the Board’s inflation and productivity analyses; and (3) benchmarking to assess the reasonableness of the distributor’s forecasts</td><td>Composite Index</td></tr>
<tr><td>Productivity</td><td>Peer Group X-factors comprised of: (1) Industry TFP growth potential; and (2) a stretch factor</td><td>Based on 4th Generation IR X-factors</td></tr>
<tr><td colspan="2">Role of Benchmarking</td><td>To assess reasonableness of distributor cost forecasts and to assign stretch factor</td><td>n/a</td></tr>
<tr><td colspan="2" rowspan="2">Sharing of Benefits</td><td colspan="3">Productivity factor</td></tr>
<tr><td>Stretch factor</td><td>Case-by-case</td><td>Highest 4th Generation IR stretch factor</td></tr>
<tr><td colspan="2">Term</td><td>5 years (rebasing plus 4 years).</td><td>Minimum term of 5 years.</td><td>No fixed term.</td></tr>
<tr><td colspan="2">Incremental Capital Module</td><td>On application</td><td>N/A</td><td>N/A</td></tr>
<tr><td colspan="2">Treatment of Unforeseen Events</td><td colspan="3">The Board’s policies in relation to the treatment of unforeseen events, as set out in its July 14, 2008 EB-2007-0673 Report of the Board on 3rd Generation Incentive Regulation for Ontario’s Electricity Distributors, will continue under all three menu options.</td></tr>
<tr><td colspan="2">Deferral and Variance</td><td>Status quo</td><td>Status quo, plus as needed to track capital spending against plan</td><td>Disposition limited to Group 1
Separate application for Group 2</td></tr>
<tr><td colspan="2">Performance Reporting and Monitoring</td><td colspan="3">A regulatory review may be initiated if a distributor’s annual reports show performance outside of the ±300 basis points earnings dead band or if performance erodes to unacceptable levels.</td></tr>
</table>

The Board is establishing three rate-setting methods. Each distributor will select the method that best meets its needs and circumstances, and apply to the Board to have its rates set on that basis. 4th Generation Incentive Rate-setting (“4th Generation IR”), which builds on 3rd Generation IR, is most appropriate for distributors that anticipate some incremental investment needs will arise during the plan term. The Board expects that this method will be appropriate for most distributors.

Distributors with relatively steady state investment needs (i.e., primarily sustainment), may prefer the Annual Incentive Rate-setting Index (“Annual IR Index”).

The Custom Incentive Rate-setting (“Custom IR”) method may be appropriate for distributors with significantly large multi-year or highly variable investment commitments with relatively certain timing and level of associated expenditures.

2.2.1 Description of the Three Rate-setting Methods

4th Generation IR

Building on the current 3rd Generation IR, the 4th Generation IR method includes certain enhancements to better align indexing of rates with the inflation faced by distributors in Ontario and to strengthen the efficiency incentives inherent in the rate-adjustment mechanism. The 4th Generation IR method will be appropriate for distributors that anticipate that some incremental investment needs may arise during the term of the rate method.

Under this method, rates are set on a single forward test-year cost of service basis and subsequently indexed by the 4th generation price cap index formula. The Board will retain a comprehensive price cap form of adjustment mechanism. The Board believes that the price cap approach, like that used in the Board’s earlier IR plans, continues to be appropriate for most distributors.

The Board has determined that the term for 4th Generation IR will be five years (rebasing plus 4 years). This longer term will better align rate-setting and distributor planning, strengthen efficiency incentives, support innovation and help manage the pace of rate increases for customers.

A distributor on 4th Generation IR may request early termination and seek to have its rates rebased if it meets the Board's criteria for early rebasing.[3] As noted previously, a regulatory review may be initiated if the distributor performs outside of the ±300 basis points earnings dead band or if its performance erodes to unacceptable levels.

Annual Adjustment Mechanism

As with current 3rd Generation IR, the allowed rate of change in the price of regulated services will be adjusted by the growth in an inflation factor minus an X-factor.

The Inflation Factor

Under price cap mechanisms, changes in price indices are reflected in allowed changes in output prices for regulated services (i.e., indices escalate the allowed prices).

The inflation factor could be established in one of two ways: either an industry-specific price index ("IPI") designed to track the inflation of the industry inputs, or a macroeconomic index. The Board has consulted with stakeholders on several occasions over the last ten years on inflation factors. The merits of, and concerns

[3] In keeping with the Board's approach as set out in its April 20, 2010 letter, a distributor that seeks to have its rates rebased earlier than scheduled must justify, in its cost of service application, why early rebasing is required and why and how the distributor cannot adequately manage its resources and financial needs during the remainder of the 4th Generation Plan term.

associated with, an IPI were summarized by the Board in its July 14, 2008 EB-2007-0673 Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors as follows:

> …an IPI would track industry input price fluctuations better than an economy-wide measure. It may better mitigate significant gains and losses that might result from the failure of a macroeconomic index to track industry input price inflation. However, the Board observes that the implementation of the IPI methodology that was used in 1st Generation IR with recent data produces a very volatile index, as shown in the illustrative example presented in the [Staff] Discussion Paper. Such volatility could be harmful to both ratepayers and distributor shareholders, if reflected in rates. The Board believes that further research is required on the methodological approach to address such volatility and to ensure that the chosen sub-indices appropriately track the inflation faced by the industry.[4]

The Board has concluded it is now appropriate to adopt a more industry specific inflation factor for 4th Generation IR. Concerns regarding volatility will be mitigated by the methodology selected by the Board. The Board also will be guided by the following:

- the inflation factor must be constructed and updated using data that is readily available from public and objective sources such as, for example, Statistics Canada, the Bank of Canada, and Human Resources and Social Development Canada;
- to the extent practicable, the component of the inflation factor designed to adjust for inflation in non-labour prices should be indexed by Ontario distribution industry-specific indices; and
- the component of the inflation factor designed to adjust for inflation in labour prices will be indexed by an appropriate generic and off-the-shelf labour price index (i.e., not distribution industry-specific)

[4] At pp. 10-11.

X Factors

The Board described the components of an X-factor in its July 14, 2008 EB-2007-0673 Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors as follows:

> The productivity component of the X-factor is intended to be the external benchmark which all distributors are expected to achieve. It should be derived from objective, data-based analysis that is transparent and replicable. Productivity factors are typically measured using estimates of the long-run trend in TFP growth for the regulated industry.
>
> The stretch factor component of the X-factor is intended to reflect the incremental productivity gains that distributors are expected to achieve under IR and is a common feature of IR plans. These expected productivity gains can vary by distributor and depend on the efficiency of a given distributor at the outset of the IR plan. Stretch factors are generally lower for distributors that are relatively more efficient.[5]

The Board has concluded that X-factors for individual distributors under 4th Generation IR will continue to consist of an empirically derived industry productivity trend (productivity factor) and stretch factor, but will be based on Ontario Total Factor Productivity (TFP) trends.

All distributors will be subject to the same productivity factor that will be set in advance for the purposes of the 4th Generation method. The Board will continue to use an index-based approach for the derivation of an industry productivity trend to form the basis for the productivity factor. The Board will update the industry productivity factor every five years (e.g., the update after 2014 would be in 2019).

The Board's approach in relation to the use and assignment of stretch factors under 3rd Generation IR will continue under 4th Generation IR. Distributors will continue to be assigned annually to one of three efficiency cohorts. The Board will make these

[5] At page 12.

assignments on the basis of total cost benchmarking evaluations. As is the case currently, each group will have its own specific stretch factor. The assignments will continue to be revised annually to reflect changes in efficiencies in the sector. The Board will further consider whether the current three stretch factor values of 0.2, 0.4, and 0.6 continue to be appropriate or whether there should be greater differentiation between the three values. The Board will determine the appropriate stretch factor values for the three efficiency groups in conjunction with its determination of the productivity factor for 4th Generation IR.

Incremental Capital Module (ICM)

The ICM is intended to address incremental capital investment needs that may arise during the IR term. Under 4th Generation IR, the Board's policies in respect of ICM in effect under 3rd Generation IR will continue to apply.

In 2011, the Board revised its *Filing Requirements for Electricity Transmission and Distribution Applications* to clarify the ICM specifications on how to calculate the incremental capital amount that may be recoverable when a distributor applies for an ICM. In the Filing Requirements issued in June 2012, the ICM was further revised to remove words such as "unusual" and "unanticipated" as prerequisites to an application for incremental capital, although the requirement that the proposed expenditures be non-discretionary remains.

Custom IR

In the Custom IR method, rates are set based on a five year forecast of a distributor's revenue requirement and sales volumes. This Report provides the general policy direction for this rate-setting method, but the Board expects that the specifics of how the costs approved by the Board will be recovered through rates over the term will be determined in individual rate applications. This rate-setting method is intended to be customized to fit the specific applicant's circumstances. Consequently, the exact nature of the rate order that will result may vary from distributor to distributor.

The Custom IR method will be most appropriate for distributors with significantly large multi-year or highly variable investment commitments that exceed historical levels. The Board expects that a distributor that applies under this method will file robust evidence of its cost and revenue forecasts over a five year horizon, as well as detailed infrastructure investment plans over that same time frame. In addition, the Board expects a distributor's application under Custom IR to demonstrate its ability to manage within the rates set, given that actual costs and revenues will vary from forecast.

The Board has determined that a minimum term of five years is appropriate. As is the case for 4th Generation IR, this term will better align rate-setting and distributor planning, strengthen efficiency incentives, and support innovation. It will help to manage the pace of rate increases for customers through adjustments calculated to smooth the impact of forecasted expenditures.

The adjudication of an application under the Custom IR method will require the expenditure of significant resources by both the Board and the applicant. The Board therefore expects that a distributor that applies under this method will be committed to that method for the duration of the approved term and will not seek early termination. As noted above, however, a regulatory review may be initiated if the distributor performs outside of the ±300 basis points earnings dead band or if its performance erodes to unacceptable levels.

Annual Adjustment Mechanism

The allowed rate of change in the rate over the term will be determined by the Board on a case-by-case basis informed by empirical evidence including:

- the distributor's forecasts (revenues and costs, including inflation and productivity);

- the Board's inflation and productivity analyses; and
- benchmarking to assess the reasonableness of distributor forecasts.

Expected inflation and productivity gains will be built into the rate adjustment over the term.

Capital Spending

There will not be an ICM in the Custom IR method. Under this method, distributors will be expected to operate under their Board-determined multi-year rates.

Under Custom IR, planned capital spending is expected to be an important element of the rates distributors will be seeking, and hence will be subjected to thorough reviews by parties to the proceeding. Once rates have been approved, the Board will monitor capital spending against the approved plan by requiring distributors to report annually on actual amounts spent. If actual spending is significantly different from the level reflected in a distributor's plan, the Board will investigate the matter and could, if necessary, terminate the distributor's rate-setting method. A distributor on the Custom IR method will have its rate base adjusted prospectively to reflect actual spend at the end of the term, when it commences a new rate-setting cycle. This is consistent with the Board's existing policies in relation to incremental capital under 3rd Generation IR.

Annual IR Index

The Annual IR Index will be appropriate for distributors with primarily sustainment investment needs. The Annual IR Index is intended to provide a rate-setting approach that is simpler and more streamlined than the other two. Among other things, there is no forecast cost of service review under this method. Rates are adjusted by a simple price cap index formula. Initial rates are set by applying this adjustment to existing rates. The annual rate adjustments are designed to reflect "steady-state mode" operations – that is, rate adjustments will be comparatively minor.

Distributors, who apply under this method for 2014 rates or later, must have had a cost of service hearing in 2008 or later. The Board also expects that a distributor applying under this method will not be exceeding its approved annual ROE by more than 300 basis points.

Like other rate setting methods, a rate application under the Annual IR Index must also include a five year forecast of capital investments, except as noted in section 5.2 of this Report dealing with transitional issues. However, as indicated in Chapter 3, the scope and level of detail required in this plan will be proportional to the scope and magnitude of the proposed investments. As with all the rate-setting methods, annual reporting will be required from distributors on the Annual IR Index.

The prudence review associated with the disposition of Group 2 variance and deferral accounts makes their disposition generally incompatible with the design of the Annual IR Index. For that reason, a distributor that applies to have its rates set under the Annual IR Index is expected to limit requests for disposition of deferral and variance accounts to Group 1 accounts while it is on the Annual IR Index. If a distributor is seeking the disposition of any Group 2 accounts, that review and disposition will need to be the subject of a separate application.

Given the nature of the rate adjustments under this method, the Board does not believe that it is necessary to establish a fixed term for it, and a distributor whose rates have been set under it may apply to have its rates rebased and set under a different method at any time. As noted previously, however, a regulatory review may be initiated if the distributor performs outside of the ±300 basis points earnings dead band or if its performance erodes to unacceptable levels.

Annual Adjustment Mechanism

Under the Annual IR Index rates will be adjusted annually by the growth in an inflation factor minus an X-factor.

Inflation Factor

The inflation factor determined for use in 4^{th} Generation IR will also be used in the Annual IR Index.

X-Factor

Under the Annual IR Index, the Board will index rates by a percentage of the inflation factor so that annual adjustments under the Annual IR Index include recognition of expected productivity gains over time. This is particularly important given that there is no fixed term for this plan. To achieve this, the Board has determined that the X-factor for the Annual IR Index will be set after the Board's determination of the X-factor values for 4^{th} Generation IR. The X-factor for the Annual IR Index will be the same as the highest X-factor set for 4^{th} Generation IR in 2014, as updated every five years. This will ensure that the resultant rate adjustment under the Annual IR Index is equal to the lowest rate adjustment under 4^{th} Generation IR. All distributors on the Annual IR Index will be subject to the same X-factor. When updated by the Board, the new X-factor will automatically be applied to all distributors that are then on the Annual IR Index.

Capital Spending

There will be no ICM in the Annual IR Index. The method presumes a largely steady-state or sustainment mode of operation by the distributor.

2.3 Decoupling

In 2010 the Board initiated a consultation process in relation to revenue decoupling mechanisms. The focus of that consultation was to examine the extent of revenue erosion due to, among other things, energy conservation efforts. The Board issued a consultant's report for stakeholder comment. That report contained a review of revenue decoupling mechanisms implemented in other jurisdictions and proposed options for consideration in Ontario.[6]

The Board indicated, when it initiated the renewed regulatory framework project in 2010, that the revenue decoupling consultation would proceed once there was substantial completion of the renewed regulatory framework policy initiative. The Board is of the view that it is now appropriate to resume the revenue decoupling initiative. Information regarding this initiative will be provided in due course.

2.4 Rate Mitigation

Rate mitigation has been a policy of the Board since 2000. At that time, the Board established a requirement that distributors *consider* mitigation where total bill increases for any customer class exceed 10%.[7] Since only consideration and not implementation of mitigation is required, this percentage is referred to as a "soft" threshold. The most recent articulation of the Board's mitigation policy confirmed the continuation of the "soft" 10% threshold for the filing of mitigation plans and provides guidance to distributors on preparing those plans.[8] In its mitigation plan a distributor may propose any, or no, mitigation mechanism as may be suitable in a particular circumstance.

[6] Lowry, Mark Newton, Ph.D., et al., Pacific Economics Group Research LLC. Review of Distribution Revenue Decoupling Mechanisms. March 19, 2010.
[7] January 18, 2000 Decision with Reasons in a proceeding to determine certain matters relating to the proposed Electricity Distribution Rate Handbook (RP-1999-0034).
[8] Report of the Board May 11, 2005 – 2006 Electricity Distribution Rate Handbook, p. 90.

2.4.1 Mitigation Policies under the Renewed Regulatory Framework

An objective for the development of a renewed regulatory framework is to ensure that distributors are encouraged to manage the prioritization and pace of network investments having regard to the total bill impact on customers. This prompted the Board to include the re-examination of its rate mitigation policy as part of the renewed regulatory framework consultation.

Stakeholder Views

There was broad support for the idea that distributors should consider mitigation when engaged in planning, ensuring that capital and OM&A expenditures are paced and prioritized in a manner such that costs are smoothed and minimized over the long term. Ensuring that the Board’s approach to rate setting is designed such that rate increases are more gradual also received support from stakeholders. Conflicting views were expressed about whether the Board should consider total bill increases for rate mitigation purposes. A hybrid approach was proposed under which distributors would be required to consider anticipated total bill increases when planning investments. However, mitigation after the revenue requirement has been determined would only apply in relation to anticipated increases in distribution rates.

Stakeholder’s comments reinforced that mitigation may not necessarily be appropriate in all circumstances. Some argued that the threshold should be “soft”, thereby providing more flexibility in determining when the filing of a mitigation proposal is required. Other stakeholders, however, supported a firm and consistently-applied threshold, arguing that this will achieve greater predictability for both ratepayers (in relation to their electricity costs) and distributors (in relation to the regulatory process).

There was agreement among most stakeholders that, regardless of methodology, an empirical threshold should be developed. Proposals for a methodology on which to base the threshold include: a customer ‘willingness to pay’ survey or an ‘economic tolerance’ study; a factor of an inflation index such as the Consumer Price Index; and the establishment of criteria rather than relying on a specific figure.

In general, stakeholders were comfortable with continued use of conventional mechanisms but believed that alternative mechanisms should be further explored.

The Board's Conclusions

The Board has concluded that it will maintain its current policy with respect to rate mitigation. The implementation of the renewed regulatory framework should make the need for mitigation of large rate increases less likely as controls to address cost increases are integrated into the planning and rate-setting processes, and each distributor will be able to choose the rate-setting approach that best suits its particular investment profile. The Board will expect distributors to consider total bill increases when they engage in planning, an exercise that will be facilitated under the integrated approach to network planning described in Chapter 3, and to demonstrate to the extent possible the responsiveness of their planned capital and OM&A expenditures to the need for reasonably stable and affordable rates for customers. The Board is therefore of the view that changes to its rate mitigation policy are not necessary at this time. Once the Board and stakeholders have gained experience with the new rate-setting methods, the Board may revisit this issue if the need arises.

The Board further concludes that it is not necessary at this time to limit the mitigation mechanisms that distributors may want to propose. The Board will continue to evaluate proposed mechanisms on a case-by-case basis.

2.5 Implementation

Issues related to the inflation and productivity adjustment mechanisms have been explored in several different consultations over the last ten years. The Board has benefited from those consultations and has gained significant experience applying the results of those consultations. Consequently, the Board is of the view that the most expeditious way to reach a determination on these issues is through a Board-led stakeholder conference followed by written submissions. To inform the conference, new inflation, productivity and stretch factors, will be developed in consultation with stakeholders as part of the performance, benchmarking and rate adjustment indices work described in Chapter 4. The Board expects to issue its determinations on these issues in mid-2013.

Product	**Planned issuance**	**Process**
Determination of inflation & productivity factors, and stretch factors	June 2013	Stakeholder conference followed by written submissions
Revised Filing Requirements for cost of service rate applications (and IR adjustment if necessary)	June 2013	Consolidation of work from Network Infrastructure Investment Planning and Performance Measurement
Board determination on stretch factor assignments for 4th Generation IR	July 2013	As per current process

3 Distribution Infrastructure Investment Planning

Under the renewed regulatory framework, good planning is necessary to ensure that the Board's outcomes as set out in Chapter 1 are being achieved. The Board's approach to rate-setting described in Chapter 2 also depends on effective planning by distributors. The Board needs evidence that a distributor's planning and prioritization process is sufficiently rigorous to support and justify its proposed capital budget. Distributor plans must therefore demonstrate consideration of all relevant factors, including the needs of existing and future customers and the costs to meet them, and that planning has been informed by appropriate consultation with customers, municipalities and neighbouring distributors and transmitters where applicable.

3.1 An Integrated Approach to Distribution Network Planning

3.1.1 Planning as the Foundation for Rate-Setting

A number of Board planning requirements have evolved over time, and different regulatory instruments have been issued in response to specific regulatory needs. Figure 1 illustrates the Board's current regulatory framework. It sets out the relationships between a distributor's asset management and network investment planning processes, notes the Board's regulatory instruments that call for distributors to file certain network planning information, and identifies the information to be provided.[9]

The Board's filing requirements identify the planning horizon for different types of investment. Section 2.5.2.4 of the Board's *Filing Requirements for Transmission and Distribution Applications* (the "CoS Filing Requirements")[10] stipulates that, at a minimum, a three-year forecast of capital expenditures, covering the test year plus two

[9] Section 2 of the *Staff Discussion Paper on Distribution Network Investment Planning* summarizes the Board's current approach.
[10] Revised version issued June 28, 2012.

subsequent years, must be filed. The Board's *Filing Requirements: Distribution System Plans – Filing under Deemed Conditions of Licence*[11] ("GEA Filing Requirements") state that "GEA Plans" should cover a five year horizon. The Board understands that distributors typically use five- to ten-year horizons for their own internal planning purposes. The GEA Filing Requirements are currently the only ones that integrate regional considerations and call for broader consultation

Stakeholder Views

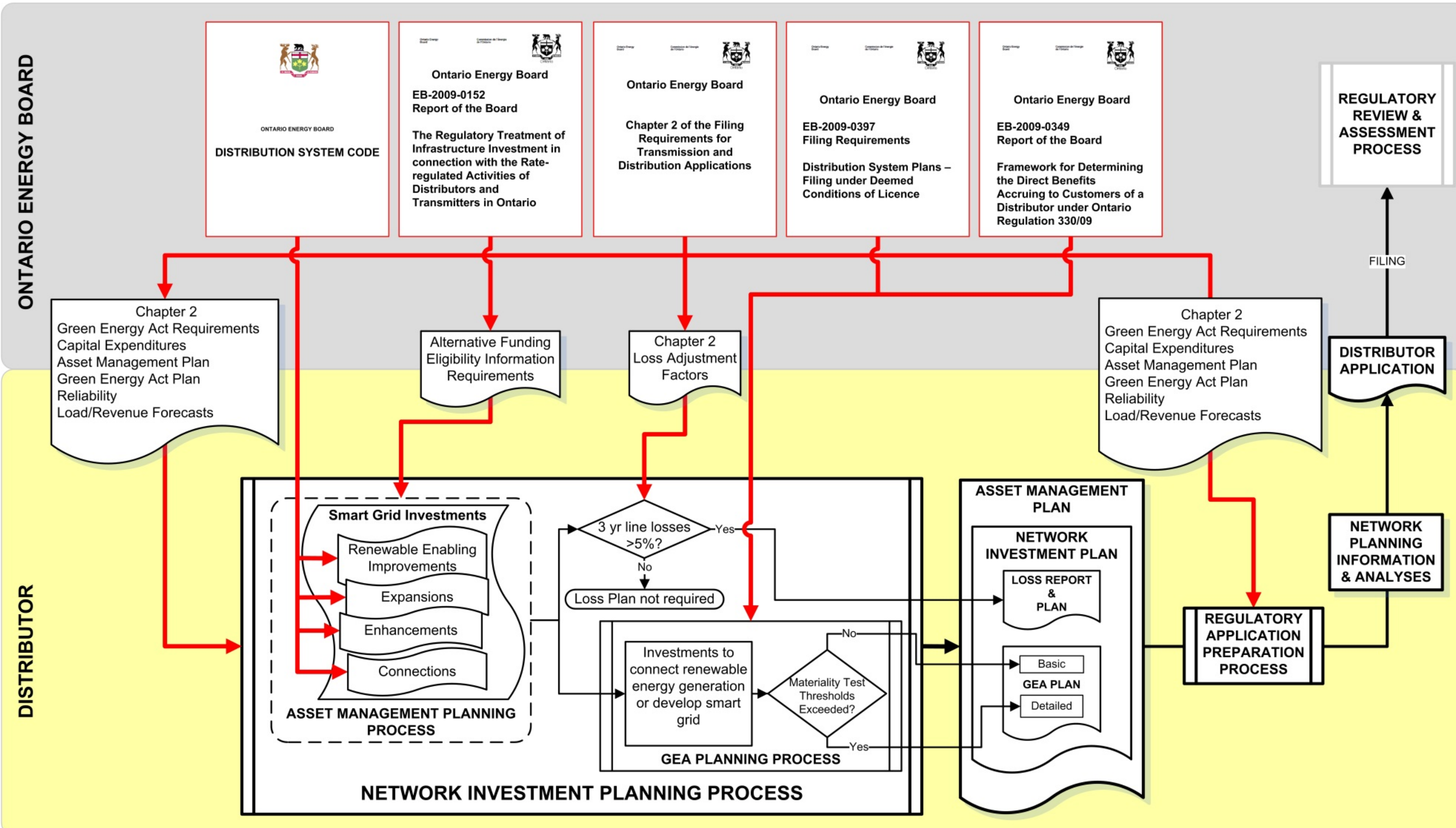
There was wide-spread stakeholder support for integrated network planning, although some stakeholders noted that certain investment drivers are inherently unpredictable. Stakeholders suggested that integrated planning would facilitate the identification and analysis of trade-offs amongst different investment options, promote sustainable least cost planning, and support optimized regional infrastructure planning.

Stakeholders generally agreed that a longer term view is needed in relation to investment planning, noting among other things that a multi-year approach better accommodates planning for large investments and allows greater scope to prioritize and pace investments and smooth rate increases. Reconciling long-term capital planning with shorter-term rate cycles and accommodating differences between transmission and distribution investments in terms of the time between planning and "in service" status were noted as challenges. Distributors largely favoured a planning horizon of three to five years as the minimum standard. Some stakeholders suggested that planning information be updated annually.

Several stakeholders underscored that the implementation of an integrated approach to planning must include the consolidation, simplification or standardization of the Board's various planning-related filing requirements.

[11] Revised version issued May 17, 2012.

Figure 1: Current Regulatory Framework for Distribution Network Planning



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The Board's Conclusions

The Board concludes that, in order to have distribution plans that support the Board's performance outcomes approach to rate-setting, an integrated approach to infrastructure planning is required. Under an integrated approach, all categories of network investments will be planned together, including investments for the renewal and expansion of networks and, where applicable, investments for the connection of renewable generation facilities, investments for smart grid development and implementation, and investments identified in the course of regional infrastructure planning exercises. An integrated approach to planning will provide a foundation for the setting of distribution rates and lead to optimized investments that support the achievement of the outcomes identified by the Board.

The Board will work to consolidate its various planning-related filing requirements. Harmonization and consolidation of these regulatory requirements can facilitate planning that will better support the achievement of the desired outcomes of the renewed regulatory framework. To the extent practicable, the terms and definitions used for asset management and investment planning information filings will be standardized to enhance clarity, consistency, and comparability. Also to the extent practicable, the Board will develop standardized requirements for capital plans and related filings.

Figure 2 provides a high level illustration of this approach, the main elements of which are discussed in later sections of this Chapter.

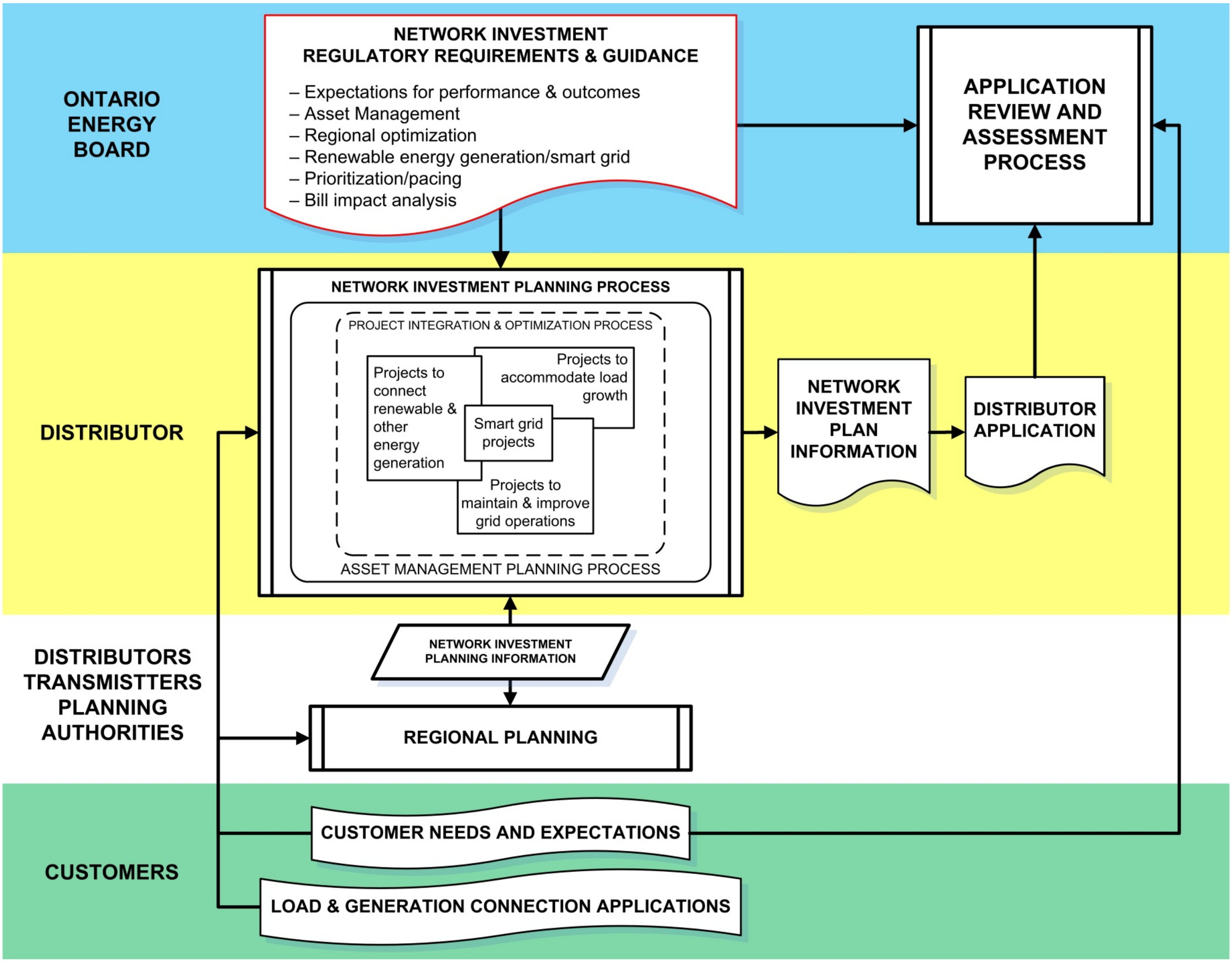
The Board further concludes that a planning horizon of five years is required to support integrated planning and better align distributor planning cycles with rate-setting cycles. This time horizon, along with the integrated approach to planning, will allow distributors to pace and prioritize projects with a view to the impact on the total bill for customers.

This planning horizon should also enhance cost predictability for both the distributor and its customers.

All distributors will therefore be required to file network investment planning information for five forecast years (where the initial or test year is the first forecast year) as part of any application for the rebasing of their rates under 4th Generation IR, or for the setting of their rates under the Custom IR method. Distributors using the Annual IR Index method will also be required to file a plan at intervals to be specified by the Board. The scope and level of detail required in the plan will depend on the scope and magnitude of the capital investments the plan is intended to support.

The Board will also monitor and measure plan implementation and plan achievement as discussed in Chapter 4.

Figure 2: Integrated Approach to Distribution Network Planning



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3.1.2 The Board's expectations for asset management and investment planning

Since 2009, the Board has required distributors to file an asset management plan if available. Where no asset management plan is available, the distributor must file information outlining its approach to the planning and prioritization of capital projects.[12]

Stakeholder Views

There was a general recognition that greater standardization of asset management plans in terms of concepts, definitions and key plan elements is needed to reduce costs, facilitate regulatory review and enhance regulatory predictability.

Stakeholders suggested different approaches for addressing uncertainty in the context of a multi-year planning horizon and for avoiding the adverse impact that deferred investments can have on customer rates. A "best practice" approach to asset management planning was suggested as a means of ensuring that investments are adequately supported and justified in distributor asset management plans.

The Board's Conclusions

The Board concludes that further development and rationalization of the Board's filing requirements should be undertaken to assist the production of planning information to better support distribution rate setting. The Board will further engage stakeholders in the development of standard requirements for asset management and capital plans. The standard requirements will facilitate the testing of the plans and ensure that the Board's expectations are clear to utilities and other stakeholders.

[12] *CoS Filing Requirements*, section 2.5.2.4.

3.1.3 Tools and methods to support proposed investments

The Board's filing requirements identify minimum requirements with respect to the quantitative data and qualitative information that is to be provided by distributors as part of their filings. The onus, however, remains on a distributor to provide the data, information and analyses necessary to justify the forecasted costs that are the basis for the distributor's proposed rates. Filings must enable the Board to assess whether and how a distributor has sought to control costs in relation to its proposed investments through the appropriate optimization, prioritization and pacing of investment expenditures.

There is a need, therefore, to consider whether specific qualitative and quantitative analyses should be required to assist the Board in its review and consideration of distributor investment plans. Whether and how experts might be used to assist in the assessment of distributor investment plans and planning processes was also noted for consideration.

Stakeholder Views

Some stakeholders endorsed the involvement of independent third party experts in the assessment of distributor planning processes and filings. It was noted that this is currently a practice in the United Kingdom, and that some Ontario distributors already routinely use third party experts for plan evaluation purposes.

Stakeholder proposals for tools and methods to support and justify distributor investments included specific quantitative analyses and verifiable or authoritative qualitative information. A variety of data and quantitative analyses were suggested.

Stakeholder views varied on bill impact estimations and associated tools. Some stakeholders were supportive of a requirement that distributors consider forecasts of the 'total bill' when developing their spending plans, identifying this as essential to the pacing and prioritization of investment in a manner that controls year-over-year rate increases and to reducing the need for mitigation at the time of Board approval. Others noted that some costs on the total bill are outside of a distributor's control, and that increases in these costs should not result in automatic offsetting adjustments to distribution investment spending.

The Board's Conclusions

As indicated in the Introduction to this Report, the Board's first two statutory objectives are key considerations for the policies described in this Chapter. Pacing and prioritization of capital investments to promote predictability in rates and affordability for customers must be a primary goal in a distributor's capital plan. The Board recognizes that factors beyond a distributor's control may add complexity and uncertainty to any effort to estimate bill impacts on customers. However, a distributor must exercise control over the pace of its own capital spending, as this factor can be an important element in the total cost of electricity to customers. To aid distributors in this essential task, standardized methods and tools should be developed for use by distributors in the preparation of their plans. In addition, the Board sees merit in receiving the evidence of third party experts as part of a distributor's application, or retaining its own third party experts, in relation to the review and assessment of distributor asset management and network investment plans (along with other evidence filed by the distributor).

The Board will further engage stakeholders on the identification and development of qualitative and quantitative approaches and tools to be used by distributors to support their investment proposals, including methodologies to assist in prioritizing and pacing proposed investments in consideration of the total bill impact on customers. The output of any methodology will need to be transparent, robust and reproducible, and include forecast information from independent and authoritative sources where these are publicly available.

3.2 Regional Infrastructure Planning

3.2.1 Background

Regional planning has been undertaken for many years in Ontario. However, until recently most distributors focused almost exclusively on the delivery of electricity to their own load customers. The *Green Energy and Green Economy Act, 2009* has created an increased need for coordinated planning among distributors and transmitters, and also among neighbouring distributors, on a regional basis. The development and implementation of the smart grid will also require regional coordination. [13]

3.2.2 Integration of Regional Considerations

Some Ontario utilities are already engaged in regional or otherwise coordinated planning exercises or discussions. In the context of the Board's conclusion that more integrated planning is needed in the renewed regulatory framework, the question is whether a more structured approach to regional infrastructure planning is required.

Stakeholder Views

Many stakeholders were supportive of a more formal approach to regional planning as a means of addressing key concerns with the current approach. In their view, the current approach is not sufficiently inclusive (in particular, ratepayer interests are under-represented) and a more formal approach would address this issue and ensure participation by all distributors. Other stakeholders, however, were of the view that the current approach is adequate.

[13] The Minister's Directive referred to later in this Chapter identifies regional coordination as a policy objective to guide the Board in the development of guidance to the industry on the development and implementation of the smart grid.

There was general agreement that any regional planning process should be a “one-step” process, with the Ontario Power Authority (“OPA”), the relevant transmitter and the relevant distributors involved in developing a single regional plan. There was also general agreement on the need for all potential solutions, including distribution and transmission infrastructure, distributed generation and conservation and demand management (“CDM”) solutions, to be considered in the context of a new regional planning process.

Some stakeholders suggested that regional plans should be approved by the Board, whether separately or in the context of a rate or leave to construct proceeding.

The Board’s Conclusions

The Board concludes that infrastructure planning on a regional basis is required to ensure that regional issues and requirements are effectively integrated into utility planning processes, which will, in turn, help promote the cost-effective development of electricity infrastructure in the Province. The effective use of regional infrastructure planning and the inclusion of regional considerations in distributors’ and transmitters’ plans will also be key in ensuring that the development and implementation of the smart grid in Ontario is carried out on a coordinated basis and that smart grid investments are made at the system level (distribution or transmission) that will best serve the interests of the region.

Distributors and transmitters will therefore be expected to file evidence in rate and leave to construct proceedings that demonstrates that regional issues have been appropriately considered and, where applicable, addressed in developing the utility’s capital budget or infrastructure investment proposal. The Board does not expect that a formal regional infrastructure plan will be required in all instances to satisfy this filing requirement. While the Board will consider regional infrastructure plans in its regulatory processes, the Board will not formally approve these plans.

The Board believes that effective regional infrastructure planning will be best achieved by allowing relevant stakeholders a further opportunity to build on their practical experience and on the input received through this consultation to date. The Board will convene a stakeholder working group to prepare a report that sets out the details of appropriate regional infrastructure planning processes, that designs the outputs of the planning process and that identifies any changes to the Board's regulatory instruments that may be needed to support the process. The Board expects the following to be reflected in that report:

- The Board expects regional infrastructure planning to be more structured, and therefore lead responsibility must be assigned. The Board believes that there is merit in having this responsibility lie with the appropriate transmitter. The transmitter will work with the OPA to identify where CDM or distributed generation options may represent potential solutions.

- Regions that will form the foundation for the process will be identified, such that all distributors will have an understanding of the regions within which they reside. The Board sees merit in having predetermined regions that are based on electrical system boundaries, and suggests that the Independent Electricity System Operator's electrical zones be used as a starting point.

- Protocols will be in place for the sharing of information among relevant parties.

- Distributors will be expected to participate in regional infrastructure planning processes.

Following receipt of that report, the Board will determine whether any changes to its regulatory instruments are required.

3.2.3 Facilitating the Implementation of Regional Infrastructure Planning through Amendment of Board Codes

Two issues relating to cost responsibility for transmission connection assets have been identified as potential impediments to the implementation of regional infrastructure planning and the execution of regional infrastructure plans.

The first issue (the "Otherwise Planned and Refund" issue) is centered on sections 6.3.6 and 6.2.24 of the Transmission System Code ("TSC"). As a general rule under the TSC, cost responsibility for transmission connection assets lies with the transmission customer, who may be required to make a capital contribution before the asset is built. Section 6.3.6 of the TSC creates an exception by stating that a capital contribution is not required for connection facilities that are "otherwise planned" by the transmitter. Section 6.2.24 of the TSC contemplates that, where a customer has made a capital contribution for the construction of a connection facility and that capital contribution includes the cost of capacity not needed by the customer, the customer is entitled to a refund of a portion of the capital contribution if that capacity is later assigned to another customer. However, that entitlement to a refund ends five years after the connection facility comes into service.

The second issue (the "Transmission Asset Definition" issue) pertains to the definition of certain transmission connection assets and the cost responsibility consequences that flow from that definition. Specifically, the question is whether certain line connection assets are more appropriately treated as network assets for cost responsibility purposes.

Stakeholder Views

Otherwise Planned and Refund Issue

Stakeholders generally agreed that changes to the current TSC cost responsibility rules for line connection assets are required to facilitate regional infrastructure planning and the ultimate execution of regional plans. Stakeholders were also broadly supportive of a shift away from the current emphasis on a 'trigger' pays model in relation to new or upgraded line connection investments.

It was noted that section 6.3.6 of the TSC can act as a disincentive to joint planning between the transmitter and distributors and that there are ambiguities in relation to when or how that section applies, as previously acknowledged by the Board.[14]

Some stakeholders identified that the effect of the five-year sunset proviso in section 6.2.24 of the TSC is that later-arriving customers that benefit from a connection asset are able to avoid contributing to the cost of that asset. It was noted that this can create an inappropriate incentive for a distributor to delay requesting additional capacity until after the five year period expires.

The Transmission Asset Definition Issue

Stakeholders were generally supportive of redefining line connection assets. Among the concerns noted with the current cost responsibility regime is that it does not take into account the evolutionary nature of the transmission system and that, in some

[14] In its September 7, 2007 Decision and Order issued in respect of a combined proceeding regarding the connection procedures of two transmitters (EB-2006-0189/EB-2006-0200), the Board stated that *"[T]here can be ambiguity with respect to whether an enhancement of the system is one which is designed primarily to address system integrity and reliability issues as identified by the transmitter, on the one hand, and those which are primarily of benefit to one or a small group of customers who have a pressing local need, on the other….That ambiguity is most easily resolved where the transmitter can demonstrate that the enhancement was identified as part of its planning process and not merely because a customer has requested it. To be clear, where planning involves joint studies between Hydro One and one or more distributor(s) to meet different timing and supply needs such as load growth, the Board views such plans as customer-driven, where a capital contribution would be required."*

cases, a distributor is responsible for the costs associated with line connection assets that perform functions beyond simply supplying the distributor.

However, stakeholders were divided on the scope of the proposed redefinition. Some stakeholders suggested that line connection assets be defined as network assets in all cases. Others proposed that line connections be so defined only in cases where such line connection assets provide other functions beyond supplying a distributor, citing the example of Dual Function Lines.[15]

It was also noted that line connection assets are not currently classified in a consistent manner. In particular, in about 50% of the cases 115/230 kV auto-transformers are currently classified as network assets (and the costs recovered from all Ontario ratepayers), while in the remaining 50% of the cases they are classified as line connection assets (and the costs recovered from only the triggering distributor and its customers). It was further noted that all distributors in a region benefit from a 115/230 kV auto-transformer, and that it is essentially impossible to determine the extent to which each transmission customer benefits from such an asset.

The Board's Conclusions

Otherwise Planned and Refund Issue

The Board concludes that a reconsideration of the TSC cost responsibility rules is desirable to facilitate the implementation of regional infrastructure planning and the execution of regional infrastructure plans. The Board believes that a shift in emphasis away from the 'trigger' pays principle to the 'beneficiary' pays principle is appropriate in that regard.

[15] The definition of certain line connections as Dual Function Lines was approved by the Board in Hydro One's EB-2006-0501 transmission rate proceeding. It addressed the Board's concerns associated with the Line Connection pool in the RP-1999-0044 transmission rate proceeding, where the Board stated that it expected the definition of the Line Connection pool to be reconsidered in Hydro One's next cost allocation and rate design proceeding.

The reference to “otherwise planned” in section 6.3.6 of the TSC implies that a transmitter is expected to plan investments without the input of transmission customers, including distributors. This is incompatible with the Board’s approach to regional infrastructure planning set out above. The Board will therefore initiate a process to propose the removal of section 6.3.6 of the TSC.

The Board also concludes that the five year limit on the requirement to provide a refund to the initial transmission customer or customers that provided a capital contribution may be creating unintended effects. The Board will therefore also propose amendments to section 6.2.24 of the TSC regarding the five-year sunset provision.

These TSC amendments would apply on a go forward basis only (i.e., only to initial customers that make a capital contribution after the amendment comes into force).

Transmission Asset Definition Issue

The Board concludes that no redefinition is required in relation to transformation connection assets for the purpose of facilitating regional infrastructure planning. However, the Board also concludes that the redefinition of certain line connection assets in a manner that better reflects the function that each asset performs will facilitate the implementation of regional infrastructure planning, and should also place distributors (and therefore all Ontario customers) on a more level playing field in terms of cost responsibility. To the extent that line connection assets are defined based on function, distributors (and their customers) will be responsible only for the costs associated with upgrades to assets that are used solely to supply a distributor or group of distributors (i.e., where such distributors are the sole beneficiaries). The end result will be somewhat akin to ‘partial’ province-wide pooling with the uploading of some transmission assets from the line connection pool to the network pool. At the same time, all distributors will remain responsible for the costs associated with some line connection assets. This approach should maintain cost discipline.

The Board has concluded that all 115/230 kV auto-transformers and the associated switchgear should consistently be defined as network assets. The rationale for classifying this subset of transmission assets as network assets was previously explained by the Board as follows:

> These unique system elements in some instances accommodate loads that are beyond a customer's requirement (e.g., autotransformers connecting the 230 kV transmission system to the 115 kV transmission system) …. In particular, use of autotransformers is seen as a means to optimize use of the transmission system as a whole in accommodating new loads safely and reliably and, most of all, in a timely manner.[16]

The Board will further engage stakeholders in the identification of all line connection assets that perform one or more functions beyond supplying the distributor and in developing criteria to be used to assess new assets and future upgrades to existing assets for redefinition purposes. That consultation will take into account the function the asset performs, reflect the 'beneficiary' pays principle and consider the frequency with which line connection assets should be reviewed to ascertain the function they provide for the purpose of future transmission rate proceedings.

Once the stakeholder consultation has been completed, the Board expects to propose amendments to the relevant provisions of the TSC with a view to integrating the new treatment of all applicable line connection assets, and will proceed with any other changes to its regulatory instruments as may be required to give effect to those amendments.

These changes are expected to apply on a go forward basis only (i.e., to new line connection assets or to upgrades to existing line connection assets that are built after the amendment comes into force). This approach will avoid retroactive changes in cost allocation and the associated rates. As a consequence, the Board notes, only future

[16] September 7, 2007 Decision and Order issued in respect of a combined proceeding regarding the connection procedures of two transmitters (EB-2006-0189/EB-2006-0200), pages 24-25.

line connection upgrades have the potential to affect the execution of regional infrastructure plans.

Pooling

During the consultation process, stakeholders provided insight into the relative merits of implementing changes to the Board's cost responsibility regime that are of a more transformative nature than those discussed above. Specifically, stakeholders commented on the potential to move to the regional or province-wide pooling of transmission connection facility costs, in whole or in part. The Board has concluded that a shift to province-wide pooling carries with it the risk of cross-subsidization, the potential for transmission overbuild and an inappropriate cost shifting between regions in the province. Regional pooling would only address those risks to some extent, and would be too complex to implement as regions may change over time and a number of distributors would be included in more than one regional pool. Moreover, the Board is satisfied that a move to any form of pooling of costs is neither necessary nor desirable at this time for the purpose of facilitating regional infrastructure planning and the execution of regional plans, given how the Board is addressing the cost responsibility issues discussed above.

3.3 Development of the Smart Grid

3.3.1 Background

With the coming into force of the *Green Energy and Green Economy Act, 2009*, several provisions were added to the OEB Act in relation to the development and implementation of a smart grid in Ontario. The Board now has a statutory objective to facilitate the implementation of a smart grid on Ontario, and it is a deemed condition of license for all licensed electricity distributors and transmitters to plan for and make smart grid investments as directed by the Board.[17]

On November 23, 2010, the Minister of Energy issued a Directive to the Board requiring it to provide guidance to licensed electricity distributors and transmitters (among possible others) regarding the Board's expectations in relation to smart grid activities. In developing that guidance, the Board is to be guided by certain parameters for three objectives for the smart grid, namely, customer control objectives, power system flexibility objectives and adaptive infrastructure objectives. The Board is also to be guided by 10 policy objectives of the government, including policy objectives pertaining to efficiency, customer value, interoperability, and privacy.

3.3.2 Smart Grid Planning and Innovation

Planning for smart grid development and implementation by electricity distributors and transmitters will be an integral part of the broader network investment planning exercise, and the Board's guidance with respect to smart grid activities will be provided in a Supplemental Report of the Board. Moreover, the Board expects that smart grid development will be coordinated on a regional basis in furtherance of the government policy objective set out in the Minister's Directive to the effect that smart grid implementation efforts should involve regional coordination in order to achieve economies of scope and scale.

Smart grid investments are eligible for the application of the "alternative" mechanisms identified in the "*Report of the Board on the Regulatory Treatment of Infrastructure Investment for Ontario's Electricity Transmitters and Distributors* (EB-2009-0152)". As noted in Chapter 4, the Board intends to explore further opportunities to embed the

[17] Paragraph 4 of section 1(1) and section 70(2.1) of the OEB Act, respectively. The *Filing Requirements: Distribution System Plans – Filing under Deemed Conditions of Licence* referred to earlier in this Chapter speak to electricity distributor planning activities in respect of smart grid demonstration projects, studies, planning exercises, education or training, and establish deferral accounts for costs associated with these activities.

facilitation and recognition of technological innovation in the renewed regulatory framework. Smart grid development and implementation activities will be a central focus of that effort, given that grid-enhancing advanced technology systems and equipment are at the heart of the smart grid.

3.3.3 Treatment of Smart Grid Investments for Rate-setting

Under the integrated approach to planning described in this Report grid-enhancing advanced information and exchange systems and equipment (which are commonly referred to as smart grid) are considered integral to all utility investment. Under this approach, no distinction is made for regulatory purposes between “smart grid” and more traditional investments undertaken by distributors and transmitters – more advanced technologies are so integrated with other activities that such distinctions are not productive.

This approach to smart grid investments and activities will best support the achievement of the objectives of the renewed regulatory framework. It facilitates more fully integrated planning, and will promote economic efficiency and the better alignment of expenditures with cost recovery so as to minimize ‘total bill’ impacts. It is also more efficient from a regulatory perspective.

3.3.4 Demarcation of Utility Role: “Behind the Meter” Activities

One of the objectives of the smart grid set out in the Minister’s Directive is customer control. Parameters for that objective include enabling access to data by authorized parties, enabling consumers to better control their consumption and providing consumers with opportunities to participate in small-scale renewable generation. The Board considers that the achievement of this customer control objective will require that “behind the meter” services and applications be available to customers. The issue of behind the meter services is closely linked to that of access to meter data. Access to meter data is key in facilitating the provision of behind the meter services and applications. The Board's regulatory framework for smart grid development and implementation should therefore facilitate data access and the implementation of behind the meter services and applications.

The question that arises is the role of distributors in the provision of behind the meter services and applications. Currently, there are private (i.e., unregulated) businesses that provide these services and applications, and that do so without Board oversight. Some distributors also provide such services on a non-utility basis as part of a CDM program. One example is the Peaksaver program offered on behalf of the OPA.

Stakeholder Views

Few stakeholders commented on this issue. One stakeholder proposed that there should be no restrictions on the provision of behind the meter services. Another maintained that distributors should be allowed to provide behind the meter CDM services, but also stated that the "demarcation should be the meter". Input was also received from the Smart Grid Working Group.

The Board's Conclusions

The Board anticipates that distributors will continue to be engaged in the provision of behind the meter services and applications that fall within the parameters set out in section 71(2) or section 71(3) of the OEB Act. In so doing, they are engaging in a <u>non-utility</u> activity. That activity must be accounted for separately from utility activities and be undertaken on a full cost recovery basis (in other words, not covered in rates). There is no element of natural monopoly in the market for behind the meter services and, therefore, the Board has concluded that customer control would be best served by the forces of market competition. The Board expects that this policy conclusion will assist distributors in planning and organizing their and their affiliate's activities.

3.3.5 Other Issues

Following the receipt of the Minister's Directive, Board staff consulted with the Smart Grid Working Group to produce a Staff Discussion Paper, which was issued in November 2011, and in that paper identified a number of key issues, including cyber-security, privacy, interoperability, customer access and the recognition of types of benefits flowing from smart grid in applications. Issues not addressed in this Report will be addressed in the Supplemental Report of the Board on Smart Grid.

3.4 Implementation

The Board will establish two new stakeholder working groups to accomplish activities dealing with distribution network planning and regional infrastructure planning. The Board will also reconvene its previously established smart grid working group. The principal tasks of these working groups will be:

- An Integrated Approach to Network Planning: To revise the Board's filing requirements for distributors and transmitters and issue guidance in accordance with the Board's conclusions in the Report. The development of an integrated set of revised filing requirements will include those related to distribution network planning, smart grid planning and regional planning.

- Regional Infrastructure Planning: To develop guidance regarding the implementation of the Board's conclusions in the Report related to moving to a more structured approach to regional infrastructure planning, as well as the appropriate redefinition of certain line connection assets and TSC cost responsibility rule changes to remove barriers related to regional plan execution.

- Development of the Smart Grid: To develop the regulatory documents to implement the Minister's Directive and the Board's conclusions in the Report.

The main products and timelines for these working groups are outlined in the table below. Further detail is provided in the remaining sections of this chapter.

	Product	Planned issuance	Process
Network Planning	Consolidated capital plan filing requirements	February 2013	Staff proposal on asset management and capital planning filing requirements Working group meetings Staff proposal on integrated filing requirements Working group meetings
Integrating Regional Planning	Consolidated capital plan filing requirements	February 2013	Working group meetings Working group report to Board (regional infrastructure planning process, filing requirements) Working group input related to filing requirements incorporated into Staff proposal on integrated filing requirements
	Amendments as necessary to TSC and DSC	April 2013	Working group meetings Working group reports to Board (asset redefinition, regional infrastructure planning process) Notice of proposed code amendments
Smart Grid	Supplemental Report of the Board	January 2013	Working group meetings Working group input related to filing requirements incorporated into Staff proposal on integrated filing requirements

3.4.1 Distribution network investment planning

The Board's filing requirements in relation to distributor asset management and investment planning information will be enhanced, and the Board will release Consolidated Capital Plan Filing Requirements in February 2013.

In order to implement the Board's requirements for integrated infrastructure planning, the Board will identify tools and methods to support proposed infrastructure investments in distributor applications, including the demonstration of how the distributor has optimized, prioritized and paced investments to take into consideration the total bill impact on customers.

3.4.2 Facilitating effective regional infrastructure planning

The Board will determine the regional infrastructure planning related information needed to support rate and leave to construct applications, and this will be incorporated into the Board's Consolidated Capital Plan Filing Requirements.

Key elements that need to be addressed in order to facilitate the move to a more structured regional infrastructure planning process include the following*:*

- The information a distributor should be required to provide to the transmitter for regional infrastructure planning purposes and the frequency at which it should be updated;
- The appropriate evaluative criteria to compare potential solutions;
- The circumstances under which the OPA should participate;
- The form in which broader consultation should take place before a regional plan is finalized; and
- Appropriate regional boundaries and the criteria to be used to establish them.

A Working Group Report to the Board will be produced, as well as a staff proposal for consolidated filing requirements. The Board expects that the section of the Report addressing regional infrastructure planning process matters will also provide input for the Board's consideration in relation to any other key elements that the working group believes should be addressed in order to facilitate the move to a more structured regional infrastructure planning process.

3.4.3 Facilitating the implementation of regional infrastructure planning

As noted in this Report, the Board believes that changes to the cost responsibility regime necessary to facilitate regional infrastructure planning will require the development of a set of criteria based on the function(s) that line connection assets perform. These changes will be effected through a notice and comment process to amend the relevant TSC sections.[18] Given the interconnected nature of these cost responsibility changes related to the redefinition of line connection assets and those involving TSC cost responsibility rule changes discussed above (i.e., "Otherwise Planned and Refund Issue"), the Board will address all of the proposed amendments in one notice and will propose the same implementation date for all amendments. This code amendment process will also address amendments to the TSC that may be required in relation to the regional infrastructure planning process matters discussed above.

The proposal for Code amendments will also be informed by a Working Group Report to the Board in relation to criteria for line connection asset redefinition and identifying the assets that meet those criteria. The Board expects any amendments made to the Codes will come into force in mid-2013.

3.4.4 Smart grid guidance

The Board will issue a Supplemental Report providing the Board's guidance on smart grid, including the integration of smart grid development into the overall regional and

[18] The redefinition of certain line connection assets may also require proposed amendments to other regulatory instruments of the Board.

network planning filing requirements. The Board expects to issue the Supplemental Report on smart grid policy in January 2013, and to integrate the smart grid work into the Consolidated Capital Plan Filing Requirements.

4 Performance Measurement and Continuous Improvement

The renewed regulatory framework is a comprehensive performance-based approach to regulation that promotes the achievement of performance outcomes that will benefit existing and future customers. The framework will align customer and utility interests, continue to support the achievement of important public policy objectives, and place a greater focus on delivering value for money.

The achievement of the performance outcomes will be supported by specific measures and targets and annual reporting. Distributor performance will be compared year over year, both to prior performance and to the performance of other distributors. To facilitate performance monitoring and distributor benchmarking, the Board will use a scorecard approach to link directly to the performance outcomes.

Under the renewed regulatory framework a distributor will be expected to continuously improve its understanding of the needs and expectations of its customers and its delivery of services, which in turn can lead to reduced costs for customers.

4.1 Monitoring Distributor Performance

Under the rate-setting approach described in Chapter 2, the Board will be setting rates under longer-term plans and allowing distributors to select the rate-setting method that best meets their needs and circumstances. Distributors will be required to undertake longer-term integrated planning that captures all categories of network planning, including those reflecting regional needs, as discussed in Chapter 3.

The Board has standards and measures for performance in place today;[19] however, the Board needs to assess whether these continue to be appropriate in light of the performance outcomes defined by the Board and the new rate setting methods. The Board also needs to consider the consequences that might flow from performance that does not meet the standards.

Benchmarking will become increasingly important, as comparison among distributors is one means of analyzing whether a given distributor is as efficient as possible.

Stakeholder Views

There was general stakeholder support for meaningful, empirically-based standards, performance measures and regulatory mechanisms, provided that the implementation costs do not outweigh the value for customers. Desirable characteristics that were identified included: focus on what customers value; promoting alignment of distributor and customer interests; and ability to accommodate differences within the distribution sector.

Stakeholder suggestions for objectives to underpin the development of distributor customer service and cost performance standards and measures included furthering market development; revealing infrastructure investment planning effectiveness or cost performance; facilitating price transparency for customers; and improving existing customer service standards.

A number of stakeholders acknowledged the cost performance incentives that are inherent in incentive regulation. Caution was expressed about implementing direct financial incentives until Board-approved measures are in place. Stakeholders were divided on process incentives; some were supportive of streamlined regulatory processes for high-performing distributors while others were opposed to limits being

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[19] These are identified in the *Staff Discussion Paper on Defining & Measuring Performance of Electricity Transmitters & Distributors.*

placed on the review of applications based on the quality of evidence or the applicant's past performance.

The Board's Conclusions

Performance Outcomes and the Electricity Distributor Scorecard

The Board is establishing performance outcomes that it expects distributors to achieve in four distinct areas:

Customer Focus: services are provided in a manner that responds to identified customer preferences;

Operational Effectiveness: continuous improvement in productivity and cost performance is achieved; and utilities deliver on system reliability and quality objectives;

Public Policy Responsiveness: utilities deliver on obligations mandated by government (e.g., in legislation and in regulatory requirements imposed further to Ministerial directives to the Board); and

Financial Performance: financial viability is maintained; and savings from operational effectiveness are sustainable.

The Board concludes that a scorecard will be used to monitor individual distributor performance and to compare performance across the distribution sector. The scorecard effectively organizes performance information in a manner that facilitates evaluations and meaningful comparisons, which are critical to the Board's rate-setting approach under the renewed regulatory framework. Distributors will be required to report their progress against the scorecard on an annual basis.

A sample of a possible scorecard based on a simple sub-set of the Board's current standards and measures (such as the service quality requirements in the *Distribution System Code*) is provided below. The sample is provided for illustrative purposes only, as the Board has not yet determined content of the scorecard to be used. The Board expects that the scorecard will evolve as appropriate standards and measures are developed to assess distributor performance against the identified outcomes.

Figure 3: Sample Scorecard

Customer Focus	Operational Effectiveness	Public Policy Responsiveness	Financial Performance
services provided in a manner that responds to identified customer preferences	*continuous improvement in productivity and cost performance; and delivery on system reliability and quality objectives*	*delivery on obligations mandated by government (specific legislation or via directives to the Board)*	*financial viability maintained; and savings from operational effectiveness are sustainable*
• Customer complaints • Connection statistics • Connection of New Service • Reconnection • Telephone Accessibility • Appointments Met • Written Response to Enquiries • Emergency Response • Telephone Call Abandon Rate • Appointments Scheduling • Rescheduling a Missed Appointment	• Distribution Losses • System Average Interruption Frequency Index (SAIFI) • System Average Interruption Duration Index (SAIDI) • Customer Average Interruption Duration Index (CAIDI) • Momentary Average Interruption Frequency Index (MAIFI)	• Electricity Conservation (Kwh) • Peak Demand Reductions (kW)	• Current Ratio • Debt Service Capability • Interest Coverage • OM&A Cost per Customer • Return on Equity

Standards and Measures

The Board will engage stakeholders in further consultation on the standards and measures to be included in the distributor scorecard. The standards and measures must be suitable for use by the Board in monitoring and assessing distributor performance against expected performance outcomes, in monitoring and assessing distributor progress towards the goals and objectives in the distributor's network investment plan, in comparing distributor performance across the sector and identifying trends, and in supporting rate-setting.

The Board has established a set of objectives to guide the consultation. Standards and measures should:

- be aligned with, and reflect a distributor's effectiveness in achieving, the performance outcomes listed in Chapter 1;
- be reflective of customer needs and expectations;
- encourage year-over-year performance gains;
- reveal current performance and signal future performance;
- reflect a distributor's effectiveness in prioritizing and pacing investment (with regard to total bill impacts) and implementing its capital plan;
- be measureable by each distributor, and be aligned with their reporting for their own internal purposes to the extent possible;
- consider the characteristics of a distributor's service territory; and
- be practical.

4.2 The Role of Benchmarking

The Board's regulatory oversight of electricity distributors is supported by benchmarking. Expanded use of benchmarking will be necessary to support the Board's renewed regulatory framework policies.

Stakeholder Views

There was general support for the continued development and use of benchmarking tools, with further empirical work on the distribution sector identified as a priority. It was noted that the cost of this exercise should not exceed its value, recognizing that there may be limits to the practical use of cost comparison and benchmarking information. Among suggestions offered for the further use and development of benchmarking tools were the use of external data, benchmarks and productivity trends to establish boundaries within which distributors should operate; the more rigorous implementation of benchmarking in rate proceedings; and the adoption of a “balanced scorecard” approach to benchmarking to reflect customer and distributor diversity.

The Board’s Conclusions

The Board concludes that benchmarking models will continue to be used to inform rate setting. The Board will continue to build on its approach to benchmarking with further empirical work on the electricity distribution sector in relation to the distributor customer service and cost performance outcomes, including: total cost benchmarking; an Ontario TFP study; and input price trend research. The Board will engage stakeholders in this effort.

The empirical work on the electricity distribution sector will inform the rate-adjustment mechanisms under 4th Generation IR and the Annual IR Index, and will inform the Board’s review and approval of applications under the Custom IR method. Consequently, regardless of the rate-setting plan under which a distributor’s rates are set, the distributor will continue to be included in the Board’s benchmarking analyses.

Benchmarking will also continue to be used to assess distributor performance. The results of further statistical methods for evaluating distributor performance will also assist the Board in assessing distributor infrastructure investment plans and in determining appropriate cost levels in rates associated with those plans. The publication of benchmark results will also continue to inform the public about distributor performance and facilitate comparisons among distributors.

4.3 Regulatory Mechanisms

The Board is committed to ensuring optimal performance and value for customers, and will continue to enhance its regulatory mechanisms where necessary to achieve this goal.   In initiating the performance-based approach, the Board will maintain its existing regulatory mechanisms, subject to certain refinements. Specifically, the X-factor will be refined as discussed in Chapter 2 and the “publication of distributor results” mechanisms referred to above (among possible others) will be integrated into the electricity distributor scorecard.

The Board’s incentive regulation approach to rate-setting creates incentives for distributors to innovate in order to operate within the price cap while continuing to meet the needs and expectations of their customers. The Board will further consider incentives directed at innovation to address system and customer requirements. While this work should consider the Board’s current policies as set out in the *Report of the Board on the Regulatory Treatment of Infrastructure Investment for Ontario’s Electricity Transmitters and Distributors*, the Board expects that new approaches may be required.

In addition, appropriate consequences should flow from unsatisfactory performance against the Board’s standards, in order to maintain the integrity of the Board’s outcome-based approach and its approach to rate-setting.

Additional regulatory mechanisms may be necessary to achieve the objectives of the renewed regulatory framework. The Board will engage stakeholders in further consultation on the following in due course:

- The establishment of an “efficiency carry-over” mechanism;
- Development of incentives to;
    - reward superior performance;
    - encourage innovation;
    - encourage asset optimization; and
- Potential consequences for inferior performance.

The development of these regulatory mechanisms will be aligned with the standards and measures referred to above.

4.4 Implementation

To establish the outcome based framework and provide for effective monitoring of distributor performance, the Board will:

- define the standards and measures that will be applicable to distributors;
- establish benchmarking models (through further empirical work);
- establish the reporting requirements applicable to distributors, including the format of the performance scorecard; and
- determine the regulatory mechanisms that will be used in conjunction with those standards and measures (in due course).

A stakeholder working group will be established to provide staff with expert assistance and to help staff review and evaluate proposals regarding performance standards, measures, and the development of benchmarking. This will also include consideration of rate adjustment indices (i.e., inflation and X factors). Staff and consultant reports will be issued for comment.

With respect to benchmarking, the objective is to establish total cost benchmarking for the 2014 rate year. Further work will involve comprehensive benchmarking (i.e., model(s) that combine standards for utility customer service and cost performance) to be applied in subsequent rate years.

The end result of this work will be a Supplemental Report of the Board expected to be issued in mid-2013. Regulatory instruments such as the Reporting and Record Keeping Requirements will be amended as necessary to implement the Supplemental Report.

Work carried out in this consultation to develop total cost benchmarking will provide the foundation for the development of the Board’s approach to comprehensive benchmarking. The overall approach and timeline for such additional work will be issued after the substantial completion of work planned for implementation for the 2014 rate year.

	Product	Expected issuance	Process
Standards and measures	Supplemental Report of the Board, including distributor scorecard	June 2013	Staff proposal Stakeholder meeting Working group meetings Board staff report to the Board (for comment) Stakeholder meeting Written comments
	Amendments to RRR if needed	July 2013	Notice and comment
Benchmarking	Supplemental Report of the Board (same document as above), plus consultant report on approach to total cost benchmarking	June 2013	Validation of data by distributors Consultant Concept paper Stakeholder meeting Working group meetings Consultant report (for comment) Stakeholder meeting Written comments

4.4.1 Issues to be addressed in relation to standards, measures and regulatory mechanisms

Working with stakeholders, the Board will consider the following areas in the context of developing a scorecard and performance standards, and measures to facilitate annual monitoring of distributor performance.

Assessing performance outcomes:

- confirm the standards and measures that best reflect a utility's effectiveness and/or continuous improvement in achieving the performance outcomes.

Effective planning & implementation:

- establish measures that best reflect a distributor's effectiveness with respect to:
  - planning - prioritizing and pacing investment with regard to total bill increases to consumers;
  - plan implementation – progress in achieving targets against the capital plan; and
  - plan achievement – achievement of the goal(s)/outcome(s) originally committed to in an approved capital plan

Regulatory reporting:

- establish the electricity distributor scorecard to effectively organize how utilities report on their performance to the Board.

Regulatory Mechanisms:

In due course, the Board will further engage stakeholders to consider the appropriate form and implementation of:

- an "efficiency carry-over" mechanism; and
- performance incentives to reward achievement of utility plan objectives, and/or encourage and reward implementation of truly innovative technologies to address system and customer requirements.

4.4.2 Issues to be addressed in relation to benchmarking

The use of OM&A data to benchmark distributors for stretch factor assignment purposes in the 3rd Generation IR plan is the foundation for a more comprehensive (e.g., total cost) benchmarking approach. Work to develop the more comprehensive benchmarking model(s) will also create the dataset necessary to estimate Ontario TFP trends.

The Board will continue to build on its approach to benchmarking with further empirical work on the electricity distribution sector in relation to the utility customer service and cost performance outcomes, including total cost benchmarking and an Ontario TFP study. This work will inform the Board determination on inflation and X factors for rate-setting.

The Board will also determine how to make expanded use of benchmarking for assessing distributor performance as well as to inform rate setting. In particular, the Board will establish how its standards for utility service and cost performance and various empirical tools and benchmarking will further inform (a) utility planning processes, (b) utility applications to the Board, and (c) the Board's review processes.

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5 Implementation and Transition

5.1 Implementation

As noted throughout the Report, additional work is required in each of the three policy areas to implement the Board's renewed regulatory framework. The policies set out in this Report are integrated and therefore will be implemented in a coherent sequence and in a manner that allows them to interact effectively. The complete listing of activities planned over the next several months is included in Appendix B.

As outlined in the implementation section of previous chapters, the Board will establish three stakeholder working groups to provide staff with expert assistance and to review and advise staff on proposals regarding the implementation tasks. The first working group will focus on performance, benchmarking and rate adjustment indices. The second group will address outstanding matters with respect to network investment planning, and the third will work on development of regional infrastructure planning processes. In addition, the Smart Grid Working Group will be reconvened. The stakeholder members of the working groups will be selected by the Board. By sharing certain members in common, working group efforts will be coordinated and mutually informed on an on-going basis.

Consultations will conclude with the issuance of filing requirements and guidance, code amendments, and/or supplemental Board policies. The Board expects that the policies in relation to the conclusions set out in this Report will be largely implemented in time for the 2014 rate year.

5.2 Transition

The Board expects that the three new rate setting methods will be available for the 2014 rate year. At that time, distributors may select the appropriate rate setting method for their utility.

The Board has established a transition plan to facilitate the early adoption of the three new rate-setting methods. The Board is aware that the preparation of a rate application can be a lengthy and resource-intensive effort. In devising the implementation and transitional measures described in this Report, the Board is attempting to balance the interest in having the new rate-setting methods available to most distributors for the 2014 rate year with the recognition of the time needed to prepare applications under the new methods. A set of tables have been provided below that represent the transition options that distributors have based on their current status in the 3rd Generation IR plan, and the timing of their rate year.

Option 1 – 4th Generation IR

Transition to full 4th Generation IR will depend on when a distributor is next scheduled to rebase under cost of service.

Option 1a – Distributor completes remaining term of 3rd Generation IR

Those distributors who are within the term of their current 3rd Generation IR (in other words are scheduled to rebase for January 1, 2015 rates or later) will continue to have their rates adjusted annually for the remaining years of their 3rd Generation IR term. The adjustment mechanism will be the same as that used for 4th Generation IR. Filing requirements for these annual adjustment applications will be available for January 1, 2014 rates.

The Board discourages distributors who are not currently scheduled to be rebased for 2014 rates from filing applications for early rebasing under the 4th Generation IR method. The Board will continue to apply the criterion regarding early rebasing enunciated in its letter of April 20, 2010: that is, that a distributor must clearly demonstrate why and how it cannot adequately manage its resources and financial needs during the remainder of its IRM period.

Option 1b – Distributor Rebases under 4th Generation IR

Complete filing requirements (including Cost of Service Filing Requirements and Consolidated Capital Plan Filing Requirements) will be available for rebasing applications under 4th Generation IR for May 1, 2014 rates. In order to provide some additional time to prepare applications, these rebasing applications may be filed by October 1, 2013. When a distributor rebases using the 4th Generation filing requirements, the total term will be 5 years.

For distributors scheduled to rebase for 2014 and planning to seek the Board's approval for January 1 rates, there will be two options available:

1) Rebase under 3rd Generation IR filing requirements (in other words, without the 5 year capital plan) and remain under IR for 4 years total (rebasing plus 3 years) with rates adjusted annually using the 4th Generation IR annual adjustment
2) Delay rebasing by one year - rebase for January 1, 2015 rates, in which case the application will be filed using the Cost of Service Filing Requirements and Consolidated Capital Plan Filing Requirements, and the total term will be 5 years.

Option 2 - Move to the Annual IR Index

Distributors may file for rates under the Annual IR Index at any time. Filing requirements for the Annual IR Index will be available for January 1, 2014 rates. Distributors on the

Annual IR Index method will be required to file five-year capital plans in accordance with the Consolidated Capital Plan Filing Requirements on a periodic basis, and perhaps as soon as with applications for May 1, 2014 rates. This timing will be confirmed when the Board issues the Consolidated Capital Plan Filing Requirements.

Option 3 - File a Custom IR application.

Distributors may file for a Custom IR as soon as the Consolidated Capital Plan Filing Requirements are available. This option will not be available for January 1, 2014 rates, but will be available for purposes of setting May 1, 2014 rates or later.

Distributors may make a Custom IR application any time within a 3rd or 4th Generation IR or Annual IR Index term. The Board will permit an exception to the early rebasing test for distributors applying under the Custom IR method in advance of their normal rebasing date. The Board's view is that the Custom IR method should be available as soon as possible for distributors with prolonged elevated investment needs. One of the Board's main concerns with early rebasing is the opportunity it affords distributors to avoid the efficiency incentives in the annual adjustment mechanism. The Board is satisfied that the Custom IR process will be sufficiently rigorous that an assessment of the adequacy of past and future productivity levels can be made and the results of that assessment can be incorporated into the distributor's future rates.

The Board anticipates that there could be a significant case load for the determination of 2014 rates as a consequence of the implementation of the new framework. Delays may occur. Any distributor intending to apply under the Custom IR method for 2014 rates is encouraged to speak with Board staff at an early point to discuss scheduling.

The Board does not intend to publish filing requirements for the Custom IR method (other than the Consolidated Capital Plan Filing Requirements) at this time, although much of the material in Cost of Service Filing Requirements will be relevant for Custom IR filers. Consistent with the conclusions set out in this Report in relation to the Custom

IR method, the onus will be on the applicant to specify and substantiate its preferred approach to multi-year rate-setting. After the Board has gained some experience with these types of applications it may publish filing requirements for Custom IR applicants.

Figure 4: Transitional Measures for Rates for May 1, 2014 or Later

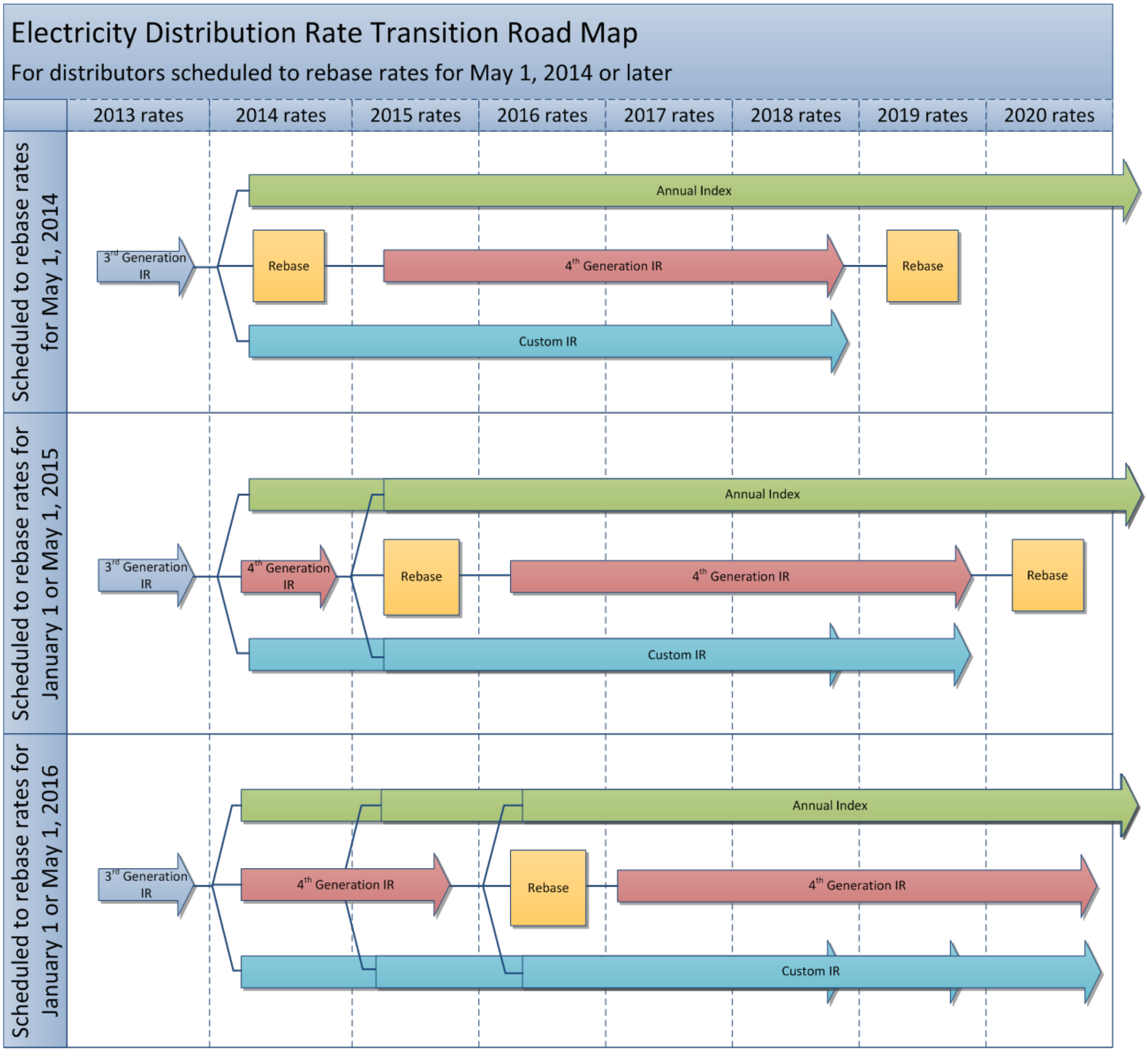
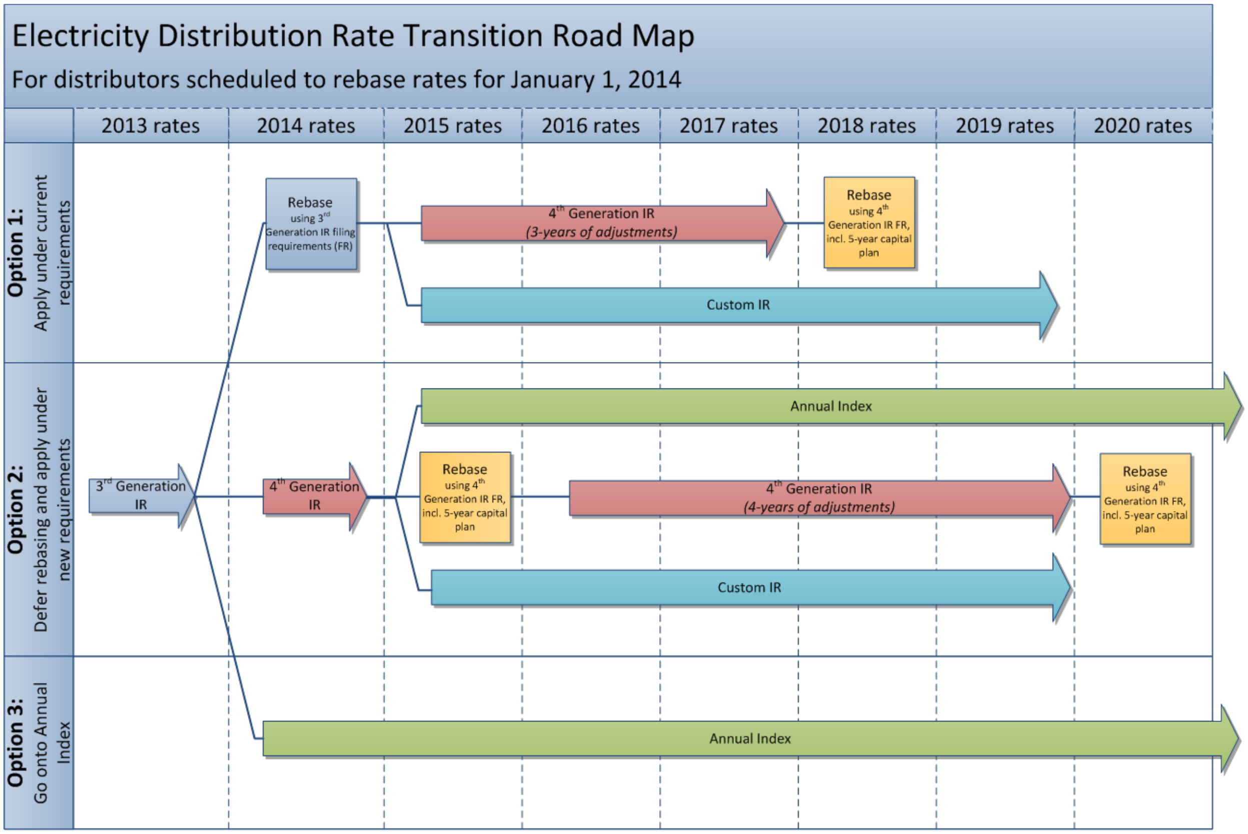


Figure 5: Transitional Measures for Rates for January 1, 2014



Appendix A: Summary of Consultation Activities to Date

Unless otherwise indicated by a prefacing identifier, all five inter-related initiatives were addressed in coordinated consultation activities.

Date	Issue / Document
Oct 27-10	The Board issued a letter announcing its intention to develop a Renewed Regulatory Framework for Electricity. • Letter
Dec 17-10	The Board issued a letter a letter initiating a consultation process to develop three key elements to a Renewed Regulatory Framework for Electricity. • Letter
Jan 13-11	Developing Guidance for the Implementation of Smart Grid in Ontario (EB-2011-0004): The Ontario Energy Board is initiating a consultation with stakeholders on the implementation of Smart Grid. The Board invites all interested parties to participate in this consultation - a Smart Grid Working Group (SGWG). Nomination to participate in the working groups is due January 24, 2011. • Letter
Jan 27-11	Board staff has posted material for the Stakeholder Conference to be held on February 2nd. • Instructions on How to Join the Stakeholder Conference via WebCast (for those not attending in person) • Draft Agenda • Presentations o Overview o Distribution Network Investment Planning (EB-2010-0377) o Rate Mitigation (EB-2010-0378) o Defining and Measuring Performance of Electricity Distributors and Transmitters (EB-2010-0379)
Jan 31-11	Developing Guidance for the Implementation of Smart Grid in Ontario (EB-2011-0004): The Board received the following Smart Grid Working Group Submissions: • Accenture • Association of Major Power Consumers in Ontario • Bell Canada • Bluewater Power Distribution Corporation • Building Operators and Managers Association • Cambridge and North Dumfries Hydro Inc. • Capgemini

Date	Issue / Document

	• Certicom Corp.
	• Chatham-Kent Hydro
	• Cornerstone Hydro-Electric Concepts
	• David O'Brien
	• Direct Energy Marketing Ltd.
	• Electrical Safety Authority
	• Electricity Distributors Association
	• Elenchus Research Associates
	• Elster Metering
	• Enbala Power Networks
	• Enbridge Gas Distribution Inc.
	• Energate - 1
	  o Energate - 2
	  o Energate - bio
	• Energent Inc.
	• Energy Aware Technology Inc.
	• Enersource
	• Erie Thames Powerlines
	• Festival Hydro Inc.
	• GE Digital
	• General Motors of Canada
	• Honeywell
	• Horizon Utilities
	• Hydro One Networks Inc.
	• Hydro Ottawa Ltd.
	• IBM
	• Independent Electricity System Operator
	• Just Energy
	• Kinectrics Inc.
	• London Property Management Association
	• Measurement Canada
	• Metering Support Services Canada Inc.
	• Milton Hydro Distribution Inc.
	• Oakville Hydro Electricity Distribution Inc.
	• Ontario Sustainable Energy Association
	• PowerStream Inc.
	• Regen Energy - 1
	• Simpleafy
	• Society of Energy Professionals
	• Telvent
	• Thunder Bay Hydro Electricity Distribution Inc.
	• Toronto Hydro-Electric System Ltd.
	• Utilismart Corporation
	• Utilities Kingston
	• Veridian Connections Inc.

Feb 14-11	Developing Guidance for the Implementation of Smart Grid in Ontario (EB-2011-0004): Board staff today issued a letter on the selection of Smart Grid Working Group members • Letter

Date	Issue / Document
Apr 1-11	Regional Planning for Electricity Infrastructure (EB-2011-0043): The Board initiated a consultation aimed at promoting the cost-effective development of electricity infrastructure through coordinated planning on a regional basis between licensed distributors and transmitters. • Board letter on Regional Planning and participation
May 4-11	Regional Planning for Electricity Infrastructure (EB-2011-0043): Stakeholder Meeting • Agenda
Jun 3-11	Regional Planning for Electricity Infrastructure (EB-2011-0043): The Board has issued Meeting Notes from the Stakeholder Meeting on Regional Planning. • Meeting Notes
Nov 8-11	The Board has issued a set of staff discussion papers and supporting consultant reports for the initiatives set out below. Details on the consultation process are set out in the cover letter. • Cover Letter • Distribution Network Investment Planning • Approaches to Mitigation for Electricity Transmitters and Distributors • Defining and Measuring Performance of Electricity Transmitters and Distributors • Developing Guidance for the Implementation of Smart Grid in Ontario • Regional Planning for Electricity Infrastructure • FAQs: Renewed Regulatory Framework for Electricity
Nov 8-11	Developing Guidance for the Implementation of Smart Grid in Ontario (EB-2011-0004): The Board has posted a Staff Discussion Paper. • Staff Discussion Paper
Nov 8-11	Regional Planning for Electricity Infrastructure (EB-2011-0043): The Board has posted a Staff Discussion Paper. • Staff Discussion Paper

Date	Issue / Document
Nov 23-11	The Board's letter dated November 8, 2011, invited interested stakeholders to participate in a two-day Information Session on the staff discussion papers and consultant reports issued that day. The session will be held on December 8 and 9, 2011. The purpose of this informal session is to give participants an opportunity to ask clarifying questions to better understand the documents. Today, Board Staff posted details regarding stakeholder participation at that session. • Details on Staff Information Session **Questions in Advance Encouraged** To facilitate an efficient and useful session, participants are encouraged to send written questions in advance to Board staff at RRF@OntarioEnergyBoard.ca. Please provide document references, if any, with your questions. Questions provided in advance will be used by staff to help kick off the session.
Dec 6-11	Board staff posted a draft agenda for the two-day Information Session planned for December 8 and 9, 2011. • Draft Agenda
Dec 9-11	Board staff posted the questions that participants of the two-day Information Session provided in writing. • Canadian Manufacturers & Exporters o December 2, 2011 Letter o Questions o Brief • Consumers Council of Canada • Electrical Contractors Association of Ontario • Just Energy Ontario LP • Low-Income Energy Network • Ontario Power Authority • Pollution Probe • Power Workers' Union • School Energy Coalition
Dec 12-11	Board staff posted material shown at the December 8 – 9 Information Session. • Power Advisory 'Bill Impact Estimation Model' presentation
Feb 6-12	The Board has issued a letter providing an update to interested stakeholders on the consultation process for its initiative to develop a renewed regulatory framework for electricity distributors and transmitters. • Letter • Attachment A - "straw man" model Regulatory Framework

Date	Issue / Document
Feb 22-12	The Board has issued a letter inviting interested stakeholders to a Stakeholder Conference, scheduled for **March 28 – 30, 2012**, as part of the Board's consultation process to develop a renewed regulatory framework for electricity distributors and transmitters. **Please note, participants are asked to register in advance by e-mail to RRF@ontarioenergyboard.ca by 4:30 p.m. on March 9, 2012**. • Letter
Mar 2-12	Regional Planning for Electricity Infrastructure (EB-2011-0043): In the Board staff information session on the Renewed Regulatory Framework for Electricity held on December 8/9, 2011, clarification of the Ontario Power Authority's ("OPA") current regional planning process was requested. In response, the OPA provided a description of their regional planning process. • Description of the OPA's regional planning process
Mar 20-12	Board staff posted a draft agenda for the two and a half-day Stakeholder Conference planned for March 28, 29, and 30, 2012. • Draft Agenda
Mar 21-12	Board Staff has posted materials from a series of Executive Roundtable Meetings held by the Chair during February and March 2012. • Presentation • List of Attendees • Meeting Notes: o Consolidated Notes from Executive Roundtables with Distributor o Consolidated Notes from Executive Roundtables with Consumer Groups o Notes from Executive Roundtable with Agencies & Transmitters o Notes from Executive Roundtable with Academics, Finance Industry, Consultants & PWU
Mar 23-12	Board Staff has posted the presentations filed by participants for the Stakeholder Conference to be held March 28-30. • Travis Allan, Counsel for Retail Council of Canada • Tom Brett, Counsel for Building and Office Managers Association • Jake Brooks, Executive Director, the Association of Power Producers of Ontario • Bob Chow, Director – Transmission Integration, Ontario Power Authority • Frank Cronin, Consultant to Power Workers Union • John Cyr, Counsel for Northwestern Ontario Associated Chambers of Commerce & Northwestern Ontario Municipal Association o Presentation • Susan Frank, VP & Chief Regulatory Officer of Regulatory Affairs, Hydro One Networks o Regional Planning o Investment Recovery • Robert Frank, Counsel for Electrical Contractor Association of Ontario • Marion Fraser, Director, Ontario Sustainable Energy Association • Rene Gatien, President & CEO, Waterloo North Hydro Inc.

Date	Issue / Document

	• Jack Gibbons, Consultant to Pollution Probe
	• Elise Herzig, President & CEO, Ontario Energy Association
	• Brennain Lloyd, Coordinator for Northwatch
	• Colin McLorg, Manager – Regulatory Policy & Relations, Toronto Hydro
	• Jack Robertson, Vice President & General Manager, Elster Metering
	• Andrew Roman, Counsel for Medium Size Distributors Group
	• Bruce Sharp, Consultant to Canadian Manufacturers & Exporters and co-sponsored by Consumers Council of Canada, Vulnerable Energy Consumers Coalition, School Energy Coalition, and Federation of Rental-housing Providers of Ontario
	    o Aegent OEPIF: unit price increase details
	    o Aegent OEPIF: unit price increase pie charts
	    o Aegent OEPIF: residential increases
	• Jay Shepherd, Counsel for School Energy Coalition
	• John Loucks, Vice-President - Corporate and Member Affairs, Electricity Distributors Association
	• George Vegh, Chair, Distribution Regulation Review Task-Force
	• Adonis Yatchew, Consultant to Electricity Distributors Association

Mar 27-12	Board staff posted an updated draft agenda for the two and a half-day Stakeholder Conference planned for March 28, 29, and 30, 2012. • Updated Draft Agenda • Attachment to Draft Agenda
Apr 5-12	The Board has issued guidance to stakeholders on issues where comments would be particularly helpful to the Board in developing a renewed regulatory framework for electricity distributors and transmitters. **Interested stakeholders are invited to file written comments by April 20, 2012** in accordance with the filing instructions set out in the letter below. • Letter
Apr 9-12	Board staff posted transcripts from the March 28-30 Stakeholder Conference. • Transcripts
Apr 24-12	Board staff has posted the written comments received by the Board by April 20, 2012. • View Comments (+)

Appendix B: Summary of Planned Consultation Activities

Target	Infrastructure investment planning			The outcome based framework		Electricity distribution rate-setting
	Distribution Network Investment	Smart Grid	Regional	Performance	Benchmarking and Rate Adjustment Indices	
2012						
October	Stakeholder working groups established to address distribution network investment planning, smart grid, and regional planning issues			Stakeholder working group established to address both performance- and benchmarking-related issues		
	A web-cast on the "Report of the Board: A Renewed Regulatory Framework for Electricity" and next steps will be held					
November	**Staff proposal** issued in relation to asset management and capital planning filing requirements	Working group meetings			**Summary of data points and time series** needed for empirical analysis issued for distributor validation	
				Staff proposal on standards, measures, and scorecard issued	**Consultant concept paper** on empirical analyses *(including consideration for inflation and productivity)* and benchmarking issued	
December	Working group meetings		**Working Group Reports to the Board** issued: (1) Asset Redefinition; (2) Regional Planning Process	A stakeholder meeting to inform and generate ideas prior to convening the working group		
				Working group meetings on standards, measures and scorecard		
2013						
January		**Supplementary report of the Board** issued: Smart grid policy		Working group meetings (continued)	Distributor validation of data points and time series due	
	Staff proposal for consolidated capital planning filing requirements issued					
	Working group meetings					

Target	Infrastructure investment planning			The outcome based framework		Electricity distribution rate-setting
	Distribution Network Investment	Smart Grid	Regional	Performance	Benchmarking and Rate Adjustment Indices	
February	Working group meetings (continued)		**Proposed amendments to the Transmission System Code** issued **If needed, proposed amendments to the Distribution System Code** issued		Working group meetings on empirical analyses *(including consideration for inflation and productivity)* and benchmarking	
	Application filing requirements and guidelines issued setting out consolidated capital planning provisions					
March				**A Board Staff Report to the Board** on standards, measures and scorecard issued for comment	**Consultant report** on methodology, data analysis, calculations, and results in relation to the preferred approach to benchmarking issued *(consideration for inflation and productivity will inform a Stakeholder Conference in April)*	
April			**Amendments to the Transmission System Code** issued	Stakeholder meeting on performance and benchmarking related issues		Stakeholder conference on appropriate values for inflation and productivity factors
May				Written *comments due on staff report and the preferred approach to benchmarking and results*		
June				**Supplemental Report of the Board** issued describing the standards, measures and scorecard reporting associated with utility outcomes for customer service and cost performance **Consultant final report** setting out the approach to total cost benchmarking that will be used by the Board issued		**Board determination** on inflation, productivity factor, and stretch factors issued **Application filing guidelines** issued setting rate application provisions
July				**If needed, proposed amendments to the Electricity Reporting & Record Keeping Requirements** issued		**Board determination on stretch factor assignments** issued