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A survey of transmission tariffs in North America

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A survey of transmission tariffs in North America

C. Lusztig^a, P. Feldberg^b, R. Orans^c, A. Olson^{c,*}^a*British Columbia Transmission Company, 1055 Dunsmuir, Vancouver, BC, Canada V7X 1V5*^b*Fasken Martineau Dumoulin, 3400 First Canadian Centre, 350–7th Avenue SW, Calgary, Alta., Canada T2P 3N9*^c*Energy and Environmental Economics, Inc., 353 Sacramento Street, Suite 1700, San Francisco, CA 94111, USA*

Abstract

One goal of electricity restructuring is to facilitate voluntary transactions in workably competitive wholesale electricity markets. Unfettered wholesale trading, however, can only take place under open and comparable access to transmission by all market participants at non-discriminatory tariffs. Since a rich body of literature exists for topics like nodal pricing, transmission rights, ancillary services, and optimal dispatch, this paper's focus is to survey the transmission tariffs *actually* used in North America to achieve open and comparable transmission access. In doing so, it provides a practical guide to developing a transmission tariff, illustrated by the survey's role in shaping the tariff filed by a company like the British Columbia Transmission Company (BCTC) with its regulator, the British Columbia Utilities Commission (BCUC).

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1. Introduction

One goal of electricity market restructuring is to facilitate the development of a workably competitive market in which voluntary transactions occur to effect mutual gains from trade [1–7]. However, unfettered wholesale trading can only take place under open and comparable access to transmission by all market participants at non-discriminatory tariffs. In North America, the opening of deregulated wholesale markets was heralded by the Federal Energy Regulatory Commission's Orders 888 and 889 issued in 1996. In addition to promulgating a pro forma open-access tariff, Order 888 encouraged utilities to go one step further by creating or joining Independent System Operators (ISOs). While several regions of the United States and Canada now have ISOs and similar organizations, others are still dominated by vertically integrated utilities offering open-access to transmission service under the pro forma tariff. As a result, there exists currently a substantial diversity of transmission tariffs across

* Corresponding author. Tel.: +1 415 391 5100; fax: +1 415 391 6500.

E-mail address: arne@ethree.com (A. Olson).

North America. This paper surveys 12 transmission tariffs used in North America as of February 2004 to achieve open and comparable transmission access [8], from the point of view of an independent transmission company in British Columbia (BC), Canada, with a mandate to improve access to wholesale energy markets for independent generators.

While not exhaustive, the 12 tariffs listed in Appendix A are chosen based on geographic coverage, resource diversity, and design variance. For example, four of the twelve tariffs are from Canadian transmission providers, with the remainder from the United States. The sample of Canadian providers includes British Columbia Hydro and power Authority (BC Hydro) and Hydro-Québec TransÉnergie (TransÉnergie) in Quebec, both of which use transmission tariffs with average-cost postage-stamp rates that do not vary by location. Both BC and Quebec are rich in hydro resources.

The Canadian sample also includes providers in Alberta and Ontario that use tariffs with rates that are partially reflective of geographically varying marginal costs. Both Alberta and Ontario rely on thermal generation as the primary source of electricity production.

The US sample includes the hydro-dominated Pacific Northwest, represented by the Bonneville Power Administration (BPA), Portland General Electric (PGE) and Puget Sound Energy (PSE), all of whom have postage-stamp rates. Finally, it includes California, New England, New York, Pennsylvania–New Jersey–Maryland (PJM), and Texas, American systems with ISOs that administer centralized wholesale energy markets. When compared to the hydro-rich Pacific Northwest, BC and Quebec, these states depend heavily on thermal generation.

There is a rich body of literature on transmission pricing, dealing with topics like nodal pricing [9,10], reliability differentiation [11], transmission rights [12,13], market power abuse [14–16], ancillary services [17], and optimal dispatch and reliable grid operation [18]. This paper does not review the theoretical aspects of transmission pricing. What it does, however, is offer a practical guide to transmission pricing in North America, illustrated by the survey's role in shaping the transmission tariff filed by a company like the British Columbia Transmission Company (BCTC) with its regulator, the British Columbia Utilities Commission (BCUC).

The paper is organized as follows. Section 2 discusses the two major design types commonly used by a transmission provider in North America today to offer services under an open-access tariff. Section 3 details the various transmission services contained in an open-access tariff, including long-term network service, short-term point-to-point services differentiated by reliability (firm vs. non-firm), ancillary services (e.g. reserves and line losses), and interconnection service. It also discusses the current status of transmission planning and retail access. Section 4 concludes by illustrating the survey's role in shaping BCTC's proposed transmission tariff.

2. Transmission rate designs in North America

There are two principal categories of transmission rate designs in use in North America today. The first category contains designs based on the open-access rules and pro forma tariff in FERC Orders 888 and 889, which we term 'open-access' designs. The main goals of an open-access tariff are comparability of access and tariff simplicity, which it achieves by offering transmission service at a 'postage stamp' rate based on average (embedded) cost pricing. The pro forma tariff has numerous users, including BC Hydro, TransÉnergie, BPA, and most other transmission providers in North America. The second category of designs has the paramount goal of developing competitive generation markets at a regional

(i.e. state or provincial, not federal) level, which we term ‘pool’ designs. Pool designs are used by ISOs or similar transmission providers in Alberta, Ontario, California, Texas, PJM, New York, and New England.

2.1. Open-access designs

An open-access design is typically used by a vertically integrated utility to allow transmission access by third parties, while continuing to provide the network service necessary to link multiple generation resources to serve loads dispersed over its service territory. Under the open-access design, transmission customers pay transaction-based fees for their use of the transmission system. The transmission revenue requirement (TRR) is allocated between point-to-point (PTP) and network service, based on a forecast of transmission usage by each type of service. A PTP customer pays a reservation charge for reserved capacity linking a point-of-receipt (POR) for power injection and a point-of-delivery (POD) for power withdrawal. The charge is equal to the allocated share of the TRR divided by the sum of expected transmission reservations. If a customer does not plan to use the reserved capacity, it may resell it.

Network customers pay a load-ratio share of the transmission owners residual TRR—that is, the portion not paid by PTP customers. The load ratios are based on network customers’ peak loads, typically measured by their contribution to monthly system peaks. Network customers designate specific PORs and PODs that link multiple resources and loads dispersed over the grid. Network customers can change their transmission usage by designating secondary PORs and PODs on a non-firm, as available, basis. This flexibility of changing POR/POD is also given to PTP service with reservations greater than 1 year, but at a lower priority than the non-firm secondary service granted to Network customers.

Requests for new transmission service are submitted via the transmission provider’s Open-Access, Same-Time Information System (OASIS), and are queued for processing based on first come first-served basis. New service requests are accommodated if there is sufficient available transmission capability (ATC) after existing uses, including PTP service already reserved and expected growth of network loads. Where available capacity exists for a new use, but will be supplanted by currently forecasted network load growth, a new customer will be offered what is available in the interim. If engineering studies determine that network upgrades are necessary to reliably accommodate a service request, the requesting customer may be required to pay part of the upgrade cost. Severe and persistent transmission congestion is generally rare, primarily because the transmission system is expanded prospectively in response to long-term service requests and anticipated network load growth. When congestion does occur due to an occasional transmission failure, generation plant outage or load spike, it is resolved by service curtailment based on a priority stack that favors firm over non-firm transmission service.

Under open-access designs, the transmission provider has an obligation to provide ancillary services, typically priced at the provider’s embedded cost. Because the transmission provider is the sole or predominant supplier of balancing energy required for reliable grid operation when the scheduled energy differs from the actual energy delivered, open-access tariffs use narrow bands and penalties to discourage excessive use of this service. To mitigate arbitrage between cost-based and market-based rates, energy imbalance rates are increasingly based on market indexes. For example, energy imbalance rates for many Northwest utilities are now based on firm energy prices at the Mid-Columbia trading hub, a major interconnection point in the state of Washington.

2.2. Pool designs

Pool designs have been implemented when two or more utilities combined operation of their transmission systems under an ISO or regional transmission organization (RTO). They are typically instituted as part of electricity market restructuring that encourages the development of competitive generation and retail markets. Instead of volumetric reservation charges, pool designs use ‘access fees’, typically assessed to loads or load-serving entities, to collect the TRR. Payment of an access fee entitles the paying customer to inject and withdraw energy anywhere on the grid.

In addition to access fees, grid users may also be required to pay a usage charge to reflect the cost of managing transmission congestion. These ‘congestion charges’ can be positive or negative, depending on whether the transmission usage contributes to or alleviates transmission congestion. Congestion management systems ration transmission capacity by changing the pattern of resource operations across the grid. For example, a generator downstream of a constraint might submit an ‘inc’ (incremental) bid to increase its generation output, while a generator upstream might submit a ‘dec’ (decremental) bid to decrease its generation output. By accepting both bids, the transmission provider changes the generation pattern to resolve congestion. The congestion charge is based on the difference between the inc and dec bids.

The most advanced pool designs integrate day-ahead and hour-ahead energy, transmission and ancillary service markets. Market participants bid to buy and sell energy and ancillary services at various locations on the grid, and the transmission provider selects the optimal resource patterns given the bids. The dispatch is efficient if the bids are made by competitive buyers and sellers and accurately inform the transmission provider of the short-run marginal benefits and costs of various services.

The interaction of all bids through this process results in market-clearing energy prices at each location on the grid. The difference between two locational energy prices defines the value of transmission capacity between the two locations and is the congestion charge to users that inject and withdraw power in these locations. Because such charges can be volatile, a user may hedge against congestion cost volatility with firm (or financial) transmission rights (FTRs). All customers can purchase FTRs in annual, seasonal or monthly auctions held by the transmission provider in advance of the actual use of transmission service. Customers paying access fees typically receive an allocation of FTRs, reducing or eliminating their need to purchase additional rights.

Users of short-term service under pool designs do not pay fixed charges because the TRR is collected from loads through access fees. However, ‘export and through’ service typically pays a separate reservation charge to ensure that loads in neighboring regions that benefit from using the transmission system also contribute to cost recovery.

New long-term service requests in jurisdictions with pool designs fall into two categories: requests for interconnection, and purchase of FTRs. Because congestion is managed through generation redispatch, new interconnections do not necessarily require network upgrades, especially when the resulting congestion cost is small relative to the cost of capacity expansion. Interconnection grants a generator the right to inject power and make supply bids into the pool. The generator can decide separately whether to pay congestion charges in order to sell to a buyer in a different location, and whether or not to acquire FTRs to help manage congestion cost volatility. FTRs can be obtained by participating in auctions, buying from an existing holder, or funding a transmission upgrade.

3. Transmission tariff details

This section describes the important elements a transmission provider must consider when developing a new tariff or revising an existing tariff. In this context, the remainder of this section summarizes the salient features of transmission tariffs in the following areas: (1) long-term service, (2) short-term service, (3) export/import service, (4) billing determinants used to calculate a transmission bill, (5) capacity-based ancillary services, (6) energy-based ancillary services, (7) planning and expansion, (8) interconnection costs and charges, and (9) retail access.

3.1. Long-term service

Table 1 is a summary of the long-term transmission service design in a sample of 12 tariffs in North America. Based on Order 888, the design of long-term service is very similar for nearly all open-access tariffs that offer point-to-point and network services. The TRR is allocated among PTP and network customers based on expected usage under each category. PTP customers reserve and pay for transmission capacity, which is then re-assignable, while network customers pay a load-ratio share of the residual TRR based on their demand at the time of the system or monthly peak load. Congestion management occurs through service curtailment; market-based congestion charges are not part of a standard open-access tariff.

While most transmission providers have adopted the FERC 888 design of long-term service without material modification, some variation does exist. In the Pacific Northwest, BPA has additional rates for transmission of non-Federal power within the Federal system and separate, pancaked rates for its Southern and Montana Interties.¹ BC Hydro and Aquila Networks Canada (Aquila) have harmonized their transmission rates to avoid rate pancaking. Under the arrangement between BC Hydro and Aquila, transmission customers only pay transmission services charges to the utility with the POD of the transaction in its service area. BC Hydro also features path-specific PTP rates that reflect the long-run incremental cost of new service over each path. Puget Sound Energy has an additional charge for transmission customers who use the system's designated 'wholesale distribution' facilities (34.5–115 kV).

Pool designs feature an access fee, generally allocated to loads, and may include usage charges calculated from a bid-based congestion management system. Owners of FTRs are entitled to revenue from congestion charges, enabling them to hedge against congestion cost volatility. Customers paying access fees typically receive an allocation of FTRs, while FTRs associated with the remaining ATC are auctioned. PJM uses a nodal approach to congestion management under which a price is calculated for every electrical 'node' on the system, whereas California, New England, New York and Texas manage congestion on a zonal basis with a single energy price determined for a collection of nodes.

Ontario is somewhat unique in that a single 'uplift cost' is included in the within-Ontario market clearing price. The uplift cost includes all congestion costs within the province. Ontario has separate market clearing prices at the New York and Michigan borders that reflect intertie congestion.

¹ Pancaked rates are the sum of regional charges for transmission from one geographic region to another geographic region. They are large when the geographic path traverses several transmission service boundaries.

Table 1
Summary of long-term service designs

<i>Canadian provinces</i>	
BC Hydro (open-access)	Standard 888 design with the reflection of incremental costs for transactions on paths that are anticipated to require an upgrade over the next 10 years
Alberta (pool design)	Pool design with access fees: TRR allocated 58% to load and 42% to generators. The class-specific TRR (load vs. generator) is net of short-term revenue for that class Loads: 60% of the load-related TRR is collected by a ratcheted demand charge and 40% by a \$/MWh usage charge Resources: 100% of the supply-related TRR is collected by a \$/MWh usage charge and a MW-month connection charge on regulated generation units Separate import and export service and fees
Ontario (pool design)	Pool design where all loads pay network service fees in \$/kW form. There is a separate export and through fee. Currently, there are no congestion charges for transmission usage within the province. Congestion costs are collected from all users through pro-rata uplift charges and the transmission usage fees
Quebec (open-access)	Standard 888 design
<i>Pacific Northwest open-access designs</i>	
Bonneville Power Administration (BPA)	Mostly standard 888 design with network and point-to-point rates covering most of the TRR. Additional rates ('Formula Power Transmission Rate' and 'Integration of Resources Rate') for transmission of non-Federal power within the Federal system. Separate, pancaked rates for the Southern Intertie and Montana
Puget Sound Energy	Standard 888 design plus additional charge for use of 'wholesale distribution' facilities
Portland General Electric	Standard 888 design
<i>US pool designs</i>	
California	Pool design with load-based access fees to recover TRR and separate fee for exports and wheel throughs. Zonal congestion management system with usage charges for zone-to-zone transactions. FTRs to hedge inter-zonal congestion are allocated to load serving entities (LSEs) based on historical use; remaining capacity made available in annual FTR auctions. Net cost of intra-zonal congestion charged to all scheduling coordinators through a grid operations charge
PJM	Pool design with load-based access fees to recover TRR and separate export fees. Nodal congestion management system with Firm Transmission Rights. Firm transmission customers are allocated rights that entitle them to a share of the FTR auction revenues. Customers may 'self-schedule' these auction revenue rights as FTRs in annual auction, or they can retain them and receive their allocated load-ratio share of FTR auction revenues
New England (ISO-NE)	Pool design with load-based access fees to recover TRR and separate export fees. Zonal congestion management system with congestion charges for zone-to-zone transactions. LSEs purchase desired quantities of FTRs in annual auction, but are allocated load-ratio share of FTR auction revenues
New York (NYISO)	Pool design with load-based access fees to recover TRR and separate export and wheel through fees. Zonal congestion management system with congestion charges for zone-to-zone transactions. Seasonal auction for transmission rights available after accounting for committed uses
Texas (ERCOT)	Pool design with load-based access fees to recover TRR and separate export fees. Zonal congestion management system with congestion charges for zone-to-zone transactions. ERCOT auctions all FTRs (annually and monthly), except those pre-assigned to municipally owned utilities and electric cooperatives which own or have a long-term contractual commitments from remote generation resources and have not implemented retail customer choice. Both auctioned and preassigned FTRs can be traded in the secondary market

3.2. Short-term service

Table 2 summarizes short-term service designs in the 12 tariffs. Under open-access designs, transmission providers can discount the rates for short-term service to improve capacity utilization

Table 2
Summary of short-term service designs

<i>Canadian provinces</i>	
BC Hydro (open-access)	The short-term price is tied to one-fourth of the difference between the AECO gas price converted to electricity prices less the electricity price at COB. The index attempts to provide a value for transmission between those two markets that is restricted on the low end by minimum prices for firm and non-firm service and on the high end by a maximum price of the full non-discounted firm rates for the same duration service. The tariff is adjusted for losses
Alberta (pool design)	There are three demand opportunity services (DOS), all subject to capacity availability: (a) recallable within 7 min; (b) recallable within an hour; (c) non-recallable with term up to 1 year. Applied to metered energy, the per MWh charge is the lowest for (a) and highest for (c). The minimum capacity payment is 75% of the per MWh charge for the scheduled capacity times hours in the transaction
Ontario (pool design)	All loads pay separate network service fees in \$/kW form. There is no distinction between short- and long-term transmission usage fees
Quebec (open-access)	Standard 888 service with some discounting for export service to promote transactions into external markets
<i>Pacific Northwest open-access designs</i>	
Bonneville Power Administration (BPA)	Standard 888 design with a lower rate for short-term reservations of 6 days or more than for reservations of 1–5 days
Puget Sound Energy	Standard 888 design with differential short-term rates for peak and off-peak: Daily peak = weekly/6 Daily off-peak = weekly/7
Portland General Electric	Standard 888 design with differential short-term rates for peak and off-peak: Daily peak = weekly/6 Daily off-peak = weekly/7
<i>US pool designs</i>	
California	In pool designs, there is no discounting of the access fees to encourage short-term use. Instead, there are periodic auctions of FTRs that provide a hedge against future congestion costs. California holds annual FTR auctions for transmission capacity available after accounting for committed uses. FTRs can be resold in the secondary market
PJM	Annual FTR auction for all transmission capacity based on single feasible dispatch. Existing firm transmission customers are allocated rights to a share of FTR auction revenues. Monthly auctions allow FTR holders to reconfigure their rights (to allow different PORs/PODs). FTRs can be resold in the secondary market
New England (ISO-NE)	Annual FTR auction for all transmission capacity based on single feasible dispatch. Existing rights-holders receive a share of auction revenue. Monthly auctions allow FTR holders to reconfigure their rights (to allow different PORs/PODs). FTRs can be resold in the secondary market
New York (NYISO)	Seasonal FTR auction for capacity available after accounting for committed uses. FTRs can be resold in the secondary market
Texas (ERCOT)	Annual FTR auction for 60% of capacity available after accounting for committed uses. Additional monthly auctions

and revenue collection. For example, PSE and PGE use differential rates for peak vs. off-peak daily service. BPA sets a lower rate for short-term reservations of 6 days or more than for reservations of 1–5 days. BC Hydro uses a formula rate, based on market indices, to promote efficient trading. The formula is based on a share of the difference in the value of energy between Alberta and the California–Oregon border.

Other than by offering FTRs with differing terms, pool designs do not distinguish between long and short-term services. All users pay congestion costs that can be offset via revenue from FTRs acquired by paying access fees, funding upgrades, or participating in auctions. The proceeds from FTR auctions are generally used to reduce access fees.

3.3. Export/import (Interties) service

Table 3 summarizes export/import service designs in the 12 tariffs. Under open-access designs, all uses of the transmission system make a contribution to recovery of the TRR. Hence, with the exception

Table 3
Summary of export and wheeling fees

<i>Canadian provinces</i>	
BC Hydro (open-access)	Standard 888 design with no separate service
Alberta (pool design)	Separate services for export and import. Subject to capacity availability, the export service (ES) is recallable on 1-h notice. The charges for ES are (1) a per MWh usage charge on transferred energy, (2) an incremental loss charge on transferred energy, and (3) a fixed (\$/billing period) transaction fee. The minimum payment is 75% of (a) and (b), applied to the capacity times the transaction's hours. The import service is structured and priced identically as ES
Ontario (pool design)	Separate export and through service with charge equal to \$1/MWh. Ontario auctions transmission rights on an annual and monthly basis to allocate uncommitted inertia capacity
Quebec (open-access)	Standard 888 design with no separate service
<i>Pacific Northwest open-access designs</i>	
Bonneville Power Administration (BPA)	Pancaked point-to-point rates for transmission over the Southern Intertie (John Day to Oregon–California border) and over the Montana Intertie (Broadview Substation to Garrison Substation)
Puget Sound Energy	Standard 888 design with no separate service
Portland General Electric	Standard 888 design with no separate service
<i>US pool designs</i>	
California	Charge for exports and wheel throughs based on MWh exported and the wheeling access charge associated with the point at which the energy exits the ISO. Congestion charges may also apply to import and export schedules
PJM	Network transmission customers pay a monthly demand charge for 'Non-Zone Network Load' (i.e. load outside of the PJM West Region and PJM Control Area), while PTP customers pay the charge for delivery at the border of PJM. Export fee does not apply to transactions sinking in the Midwest ISO. Congestion charges may also apply to import and export schedules
New England (ISO-NE)	Export charge per kW of reserved capacity based on the combined transmission facilities revenue requirement. Hourly rate is annual pool TRR divided by 8760 (the number of hours in a year). Congestion charges may also apply to import and export schedules
New York (NYISO)	Export charge based on the scheduled amount of MWh in each hour for the month
Texas (ERCOT)	Export charge based on the MWh actually exported and the access fee of the transmission provider where the inertia is located. Congestion charges may also apply to import and export schedules

of BPA, Open-access designs generally do not have a separate export service. BPA has pancaked PTP rates for transmission over the Southern Intertie and over the Montana Intertie.

Under pool designs, short-term service does not pay a cost-based transmission access charge, as the TRR is fully collected from native loads. Hence, an export fee often applies to exports or wheel through transactions, thus ensuring that their transmission use contributes to TRR recovery. In some cases, neighboring transmission providers have reached ‘seams agreements’ that allow these charges to be eliminated. Congestion charges may also apply to exports from pools.

3.4. Billing determinants

Table 4 summarizes billing determinants used by each of the 12 tariffs to calculate transmission bills. The choice of billing determinants affects a transmission user’s cost of delivering and receiving power. For example, a generator with intermittent production (e.g. wind or run-of-river hydro) generally prefers being charged on a \$/MWh energy rate that applies to MWh actually transmitted, rather than a \$/MW-month demand charge that applies to MW transmission capacity reserved to deliver an uncertain amount of MWh.

Although all open-access designs follow Order 888, diverse billing determinants are used in different jurisdictions. An example of this kind of diversity is the load-ratio calculation used in network service. The load-ratio share of network service in BC is based on 12 monthly coincident peaks of network service users. This is the FERC standard used by the vast majority of transmission providers in North America. TransEnergie, however, uses a single annual coincident peak load to determine the load-ratio share, reflecting that its system is built to meet a single winter peak.

Point-to-point service under all of the Open-access systems is billed on the basis of monthly, weekly, or daily \$/kW of reserved capacity. The hourly service rate is billed in \$/MWh. BPA has additional billing determinants for exports and for the firm transmission of non-Federal power over the main grid and secondary transmission system.

Pool designs have both access fees and usage fees, presenting more diversity than Open-access designs. The access fees are typically based on capacity billed at a \$/MW basis, while usage fees are based on energy billed at a \$/MWh basis. The MW and MWh measurements, however, can vary across jurisdictions. For instance, some jurisdictions, like New England, gross up the transmission bill to include the output of customer-owned behind-the-meter generation. Other jurisdictions, like New York, bill customers for their net load levels. Ontario has a partial net billing approach that includes demand on the transmission system from all embedded (behind the meter) generation approved after October 30, 1998.

3.5. Ancillary services

The FERC pro forma open-access tariff requires a transmission provider to offer a minimum set of comparable ancillary services (AS) to all transmission users. As shown in Table 5, BC Hydro currently offers the following AS: (a) scheduling, system control and dispatch; (b) reactive supply and voltage control; (c) regulation/frequency response; (d) energy imbalance; (e) operating reserves (spinning and non-spinning); (f) loss compensation; (g) real power losses.

While AS offered by other jurisdictions with open-access designs are similar to those offered by BC Hydro, some differences exist. For example, TransEnergie offers discounted AS rates for non-firm

Table 4
Summary billing determinants

<i>Canadian provinces</i>	
BC Hydro (open-access)	<p>Monthly network charge is based on the transmission customer's load-ratio share multiplied by 1/12 of the TRR net of point to point revenues, scheduling and dispatch revenues, and engineering services revenues</p> <p>The load-ratio share has the standard FERC definition (FERC Order 888, pp. 296–297), and is calculated on a rolling 12-month basis. A customer's bill under this method is equal to the Monthly Network TRR times the fraction defined by a customer's 12 months of coincident peak loads divided by the sum of all network customers' 12 month coincident peak loads (12 CP)</p> <p>The Point-to-Point bill is based on reserved capacity multiplied by a point-to-point charge</p>
Alberta (pool design)	<p>Demand transmission services: (a) ratcheted demand charge (\$/MW-month); (b) usage charge (\$/MWh); (c) fixed percent of pool price for operating reserve applied to metered energy; (d) \$/MW-month for other system support services (e.g. voltage support)</p> <p>Supply transmission service: usage charge (\$/MWh), incremental loss and operating reserve charges as percentages of pool price, and per MW-month connection charge for regulated generation units</p> <p>Export and import service: usage charge (\$/MWh), incremental loss charge as a percentage of pool price, plus incremental cost of system support services required by the transaction</p>
Ontario (pool design)	<p>Customer demand is the sum of (a) loss-adjusted demand supplied by the transmission system and (b) demand supplied by embedded generation for which approvals were obtained after October 30, 1998</p> <p>Provincial transmission service (applicable to transmission customers who own facilities directly connected to the transmission system and withdraw power from the system): network billing demand is the higher of (a) customer's monthly coincident peak demand (MW) and (b) 85% of the customer's peak demand during the peak period (7 am–7 pm), business days. Billing demand is multiplied by \$/kW monthly rate</p> <p>Monthly billing determinant for line and transformation connection service rate is the non-coincident peak demand (MW) in any hour in the month. Billing demand is multiplied by \$/kW monthly rates</p> <p>Retail transmission for Hydro One's core retail customers: (a) energy-only customers billed for metered or estimated consumption (cents/kWh) adjusted by total loss factor; (b) demand customers (\$/kW/month) billed for customer's peak demand in billing period</p> <p>Retail transmission for LDCs and direct-connect industrials (monthly demand > 5 MW) to low-voltage system: billing determinant for network service is peak demand from 7 am to 7 pm, business days. Billing determinant for line and transformation connection service is non-coincident peak by delivery point</p> <p>Core and acquired retail customers and low-voltage system customers who do not participate in the IMO markets are billed a wholesale market service rate in cents/kWh for metered energy adjusted by the total loss factor</p> <p>Local distribution companies (LDCs) and direct access customers also pay a monthly low-voltage facility charge in \$/kW, based on customer's average 1999 peak monthly demand between 7 am and 11 pm, business days</p> <p>Exports and wheel throughs billed at \$1/MWh of energy exported</p>
Quebec (open-access)	<p>Monthly network charge is based on the transmission customer's load-ratio share multiplied by 1/12 of the residual TRR</p> <p>The load-ratio share is based on the customer's annual coincident peak over the calendar year (1 CP)</p> <p>The point-to-point bill is based on reserved capacity multiplied by a point-to-point charge</p>

(continued on next page)

Table 4 (continued)

Pacific Northwest open-access designs

Bonneville Power Administration (BPA)	<p>Network service: network load coincident with the monthly system peak load (12 CP). Customers that use non-Federal transmission facilities to serve a portion of their firm load receive a reduction in their BPA charge. The bill is calculated as network load multiplied by the sum of the base TRR charge (\$/kW) and the load shaping charge (\$/kW)</p> <p>PTP: reserved capacity times the demand charge. Non-firm hourly PTP is billed for scheduled kWh</p> <p>Formula power: monthly charge based on billing demand multiplied by 1/12 of the sum of the main grid charge and secondary system charge. Billing demand is the higher of (a) the transmission demand; (b) highest hourly scheduled demand for the month; (c) ratcheted demand over the past 11 months</p> <p>Integration of resources: monthly charge based on \$/kW multiplied by billing demand, which is the higher of (a) annual transmission demand, (b) highest hourly scheduled demand for the month, (c) ratchet demand</p> <p>Southern Intertie Rate and Montana Intertie Rate billed as reserved capacity times the demand charge</p>
Puget Sound Energy	<p>Network service: network load coincident with monthly system peak load (12 CP) times 1/12th of the transmission revenue requirement</p> <p>PTP: reserved capacity times the demand charge</p>
Portland General Electric	<p>Network service: network load coincident with monthly system peak load (12 CP) times 1/12th of the transmission revenue requirement</p> <p>PTP: reserved capacity times the demand charge</p>
<i>US pool designs</i>	
California	<p>Access charge billed monthly as sum of the user's share of the MWh delivered by distribution company or scheduling coordinator times (TRR/12)</p> <p>Wheeling service is billed monthly as the wheeling access charge (TRR of the applicable control area) multiplied by the amount of energy wheeled, measured in MWh</p> <p>Access charge is calculated net of behind-the-meter qualifying facilities</p> <p>Usage charges for inter-zonal congestion management in cents/kWh for scheduled flows</p>
PJM	<p>Network access charge is based on the load coincident with the annual peak of the zone times (TRR/365). For exports, network access charge is based on daily load at the border of PJM coincident with the annual peak of that area times (TRR/365)</p> <p>Time lag before a Network Customer's reduced peak load will result in a reduced tariff because daily coincident peak calculated using the '12-month period ending October 31 of the calendar year preceding the calendar year in which the billing month occurs'</p> <p>Point-to-Point access charge is billed based on the maximum reserved capacity, multiplied by a zonal charge based on the zone containing the point of delivery (or border price for exports and wheel throughs)</p> <p>Usage charge in \$/MWh</p>
New England (ISO-NE)	<p>Network access charge is based on the monthly coincident peak times (TRR/12)</p> <p>Gross tariff not credited for behind-the-meter generation</p> <p>Internal Point-to-Point (PTP) access charge: reserved capacity times Internal PTP Rate</p> <p>Through or Out PTP Tariff: reserved capacity times Pool PTF (Pool Transmission Facilities) Rate</p> <p>Separate PTP rate for merchant transmission facilities</p> <p>Usage charge in \$/MWh</p>

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Table 4 (continued)

New York (NYISO)	<p>Network and point-to-point service are billed monthly on a net basis</p> <p>Imports and internal wheels are charged an access charge equal to the actual amounts (MWh) times (residual TRR/MWh)</p> <p>Exports and wheels through are charged an access charge equal to the scheduled amounts (MWh) times (residual TRR/MWh served)</p> <p>The NYPA Transmission Adjustment Charge (NTAC) is basically an access charge for the New York Power Authority, but levied on all transactions, regardless of the point of withdrawal</p> <p>Usage charges in \$/MWh</p>
Texas (ERCOT)	<p>Monthly access charge is the product of each transmission provider's monthly rate and the customer's previous year's average of the coincident peak demand for the months of June, July, August and September (4CP) that is coincident with the ERCOT 4CP demand</p> <p>Exports: monthly on-peak rate equals 1/4 of annual TRR charge times MW actually exported, while monthly off-peak rate equals 1/12th of annual TRR charge times MW actually exported</p> <p>Usage charges in \$/MWh</p>

transmission service. BPA offers lower daily rates for short-term scheduling and voltage control services for reservations of 6 days or longer. PGE and PSE provide differential rates for short-term peak and off-peak AS.

The treatment of losses is relatively uniform among open-access designs, typically priced at system average. For instance, BC Hydro defines losses as a single system average loss factor at point of receipt (POR). TransEnergy, PGE and PSE also provide only a single system average loss factor. An exception is BPA, which has differential loss factors for use of the network segment, the segment of the transmission system for delivery to the utility, direct service customers at voltages below 34.5 kV, and the Southern Intertie.

Transmission providers operating energy pools generally procure AS through auction markets or longer-term contracts, and they sometimes have additional products like regulation up and down (e.g. California), transmission must-run capacity (e.g. Alberta) and replacement reserves (e.g. ERCOT). Ontario contracts for most services except operating reserves, which are market-based.

Pricing of losses varies substantially across regional pools. Hydro One, an independent wires owner in Ontario, charges losses based on a single system average loss factor. ERCOT forecasts system-wide loss factors expressed as a percent of load for each settlement interval of the operating day. On the day following the operating day, ERCOT calculates loss factors for each settlement interval using actual system load. Notwithstanding its use of locational marginal pricing, PJM practices average loss pricing. The California Independent System Operator, however, calculates 'after the fact' losses that vary by hour and location for use in settlement. In New York, marginal losses at the delivery point are calculated on an hourly, day-ahead basis, and adjusted as a result of schedule changes in the real-time market.

3.6. Energy imbalance

An energy imbalance occurs when a transmission user's actual energy delivered differs from the scheduled amount, requiring the transmission provider to either absorb the excess or make up the shortfall. Table 6 summarizes the treatment of energy imbalances in the 12 tariffs. Open-access designs discourage excessive use of the energy imbalance service through narrow tolerance bands and penalties

Table 5
Summary of ancillary services

<i>Canadian provinces</i>	
BC Hydro (open-access)	BC Hydro offers a typical set of AS based on its costs to provide them. These services include: scheduling, system control and dispatch service; regulator/frequency response; operating reserves (spinning and non-spinning); voltage support; real power losses; and energy imbalance. Both loss compensation and the price paid or received for energy imbalances are based partially on BC Hydro's opportunity costs. The following section describes the energy imbalance prices in more detail
Alberta (pool design)	A/S costs are allocated 50% to loads and 50% to generators. Major billing determinant is a fixed percentage of pool price
Ontario (pool design)	The IMO offers a standard set of A/S based primarily on the costs from a negotiated supply agreement with Ontario Power Generation. Market-based procurement of operating reserves
Quebec (open-access)	TransEnergie also offers a typical set of A/S based on Hydro Quebec's costs to provide them
<i>Pacific Northwest open-access designs</i>	
Bonneville Power Administration (BPA)	Standard, cost-based services for regulation and frequency response, spinning reserves, supplemental reserves, voltage support and scheduling
Puget Sound Energy	Standard, cost-based A/S with differential short-term rates for peak and off-peak: Daily peak = weekly/6 Daily off-peak = weekly/7 Hourly peak = daily peak/16 Hourly off-peak = daily off-peak/24
Portland General Electric	Standard, cost-based services for regulation and frequency response, spinning reserves, supplemental reserves, voltage support and scheduling. Differential daily and hourly rates for peak and off-peak that are similar to those used by PSE
<i>US pool designs</i>	
California	Market-based; ISO procures A/S through day-ahead auction process for scheduling coordinators that do not self-provide
PJM	Market-based; PJM procures A/S through day-ahead auction process for scheduling coordinators that do not self-provide
New England (ISO-NE)	Market-based; ISO-NE procures A/S through day-ahead auction process for scheduling coordinators that do not self-provide
New York (NYISO)	Market-based; NYISO procures A/S through day-ahead auction process for scheduling coordinators that do not self-provide
Texas (ERCOT)	Market-based; ERCOT procures A/S on competitive basis and allocates arranged ancillary services to scheduling entities that do not self-provide

for deviations outside the band. For example, BC Hydro has a band of $\pm 1.5\%$, while BPA has three separate bands with increasing penalties. PSE has unique tolerance bands for its wholesale and retail customers to reflect the different scale of their loads. Energy imbalance service is increasingly priced at market, rather than the utility's embedded cost of energy, to restrict customers' ability to arbitrage between the energy imbalance service and the wholesale market.

Under pool designs, the ISO/RTO uses ancillary service auctions to procure and set ancillary service charges, including real-time balancing energy. In PJM and New England, no restrictions are placed on use of the balancing energy market. ERCOT has no restrictions for loads, but distinguishes between 'instructed' and 'uninstructed' deviations for resources, as does California. In Ontario, if a generator does not meet its obligation, a more costly generator covers the shortfall and the first generator is penalized.

Table 6
Summary of energy imbalance treatment

Company (design)	Tolerance band	Rate within band	Rate outside band
BC Hydro (open-access)	$\pm 1.5\%$ and a minimum of 2 MW	BC Hydro minimum 'buy' price for month for under-generation, RS 1821 energy rate for over-generation	125% of RS 1821 energy rate for under-generation, no compensation for over-generation
Alberta (pool design)	No tariff schedule for energy imbalance		
Ontario (pool design)	None	Market price	
Quebec (open-access)	Up to $\pm 1.5\%$, ± 2 MW	None within band if imbalance corrected within 30 days	Customer pays 10.41 cents/kWh for under-generation. For over-generation, credit of 1.28 cents/kWh
Bonneville Power Administration (open-access)	Band 1: up to $\pm 1.5\%$, ± 2 MW Band 2: between $\pm 1.5\%$, ± 2 MW and $\pm 7.5\%$, ± 10 MW Band 3: greater of $\pm 7.5\%$, ± 10 MW	Within Band 1: deviations can be returned at any time during the month to return deviation account to zero. Dow Jones Mid-C Firm Index applied to net deviations at end of month	Within Band 2: 110% of Mid-C for under-generation, 90% of Mid-C for over-generation Outside Band 2: 125% of Mid-C for under-generation, 75% of Mid-C for over-generation
Puget Sound Energy (open-access), wholesale customers	Greater of $\pm 1.5\%$, ± 2 MW	Dow Jones Mid-C Firm Index, symmetric	Greater of Mid-C, \$100/MWh
Puget Sound Energy (open-access), retail customers who can aggregate loads and resources for energy imbalance purposes	Greater of $\pm 7.5\%$, ± 1 MW	Dow Jones Mid-C Firm Index, symmetric	105% of Mid-C for under-generation, 95% of Mid-C for over-generation
Portland General Electric (open-access)	Band 1: up to $\pm 5\%$, ± 2 MW (7.5% for retail direct access customers) Band 2: between $\pm 5\%$, ± 2 MW and $\pm 25\%$ Band 3: $\pm 25\%$	Within Band 1: Dow Jones Mid-C Firm Index, symmetric	Within Band 2: 110% of Mid-C for under-generation, 90% of Mid-C for over-generation Outside Band 2: 125% of Mid-C for under-generation, 75% of Mid-C for over-generation (not applicable to retail direct access customers)

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Table 6 (continued)

Company (design)	Tolerance band	Rate within band	Rate outside band
California (pool design)	Greater of $\pm 3\%$, ± 5 MW, with 'Uninstructed Deviation Penalty' for MW outside tolerance band applied only under specified circumstances	Real-time market price at the point of imbalance	150% of real-time market price for under-generation, no compensation for over-generation
PJM (pool design)	None	Real-time market price at the point of imbalance	
New England (ISO-NE) (pool design)	None	Real-time market price at the point of imbalance	
New York (NYISO) (pool design)	Greater of $\pm 1.5\%$, ± 2 MW	Real-time market price at the point of imbalance	Greater of 150% of real-time market price, \$100/MWh for under-generation, no compensation for over-generation
Texas (ERCOT) (pool design)	Band for uninstructed resource imbalances: greater of $\pm 1.5\%$, ± 5 MW. Band expanded to $\pm 50\%$ for uncontrollable renewable resources (wind). No band for load imbalances, but imbalances $\pm 20\%$ force posting of additional collateral	Resources are paid a fraction of real-time market price for uninstructed deviations outside of band. Loads pay real-time market price	

3.7. Planning and expansion

Increased wholesale energy trading places a significant burden on transmission systems, because the facilities built by vertically integrated utilities in the pre-open-access world were generally not intended to serve transmission demands beyond those of their native loads. In the absence of significant new transmission investment, transmission congestion is expected to increase over time [19,20]. However, neither open-access nor pool designs have been very successful in effecting transmission expansion. In this context, Table 7 summarizes the planning processes used by the transmission providers offering the tariffs surveyed herein.

An integrated utility employing an open-access tariff design plans and constructs new facilities to meet the transmission needs of its firm service customers, including its own retail (or the so-called 'native load') customers and holders of long-term PTP contracts with rollover rights. Additional system upgrades are constructed in response to requests for new long-term transmission service, which are generally associated with new generation facilities. Service requests must be made through OASIS and are placed in a queue and studied on a first-in-time basis. The necessary upgrades must be completed before new transmission service can commence. Because the queue-based system processes studies individually, and because transmission investments can be 'lumpy', a single user may be required to pay the cost of a large new transmission upgrade as a condition of receiving firm service. If the cost of an upgrade or interconnection is prohibitive, the user may choose to withdraw its request.

Pool systems develop regional transmission plans that consider the needs of all member systems. Member utilities frequently continue to construct and own transmission facilities in the regional plan, although some transmission providers are beginning to seek third-party bids. Upgrades for load service are typically paid for by the loads of the local utility. New generators are not required to pay for

Table 7
Summary of planning processes

<i>Canadian provinces</i>	
BC Hydro (open-access)	BCTC responds to applications for network and PTP service posted on its OASIS. It also performs simulations to forecast ATC. Should there be insufficient ATC to accommodate new customer needs, various upgrade options are considered and the least cost option is selected. The proposed upgrades and associated schedule of implementation are documented in the Transmission System Capital Plan
Alberta (pool design)	Alberta Electric System Operator (AESO) performs system planning and development. AESO may expand system capacity without pre-contracting the planned expansion with potential users
Ontario (pool design)	The Ontario Government's Electricity Conservation and Supply Task Force issued a report in January 2004 recommending proactive transmission expansion planning, with cost recovery through transmission rates, subject to Ontario Energy Board approval (see http://www.energy.gov.on.ca). Currently, the Independent Market Operator prepares an annual assessment of the adequacy of existing and planned generation and transmission facilities on a 10-year look-ahead basis
Quebec (open-access)	TransEnergie responds to applications for network and PTP service posted on its OASIS. Hydro Quebec also prepares a 10-year plan
<i>Pacific Northwest open-access designs</i>	
Bonneville Power Administration (BPA)	BPA responds to applications for network and PTP service posted on its OASIS. BPA's Transmission Business Line also plans for regional system needs. The Infrastructure Technical Review Committee (ITRC) supports BPA's efforts to secure funding for infrastructure proposals. Once a year, the ITRC evaluates and prioritizes BPA's proposed improvement projects in a manner that will provide the most cost-effective, reliable service for the region's consumers
Puget Sound Energy	PSE responds to applications for network and PTP service posted on its OASIS. It also coordinates with the WECC Planning Coordinating Committee
Portland General Electric	PGE responds to applications for network and PTP service posted on its OASIS. It also coordinates with the WECC Planning Coordinating Committee
<i>US pool designs</i>	
California	Each transmission owner annually develops 5-year transmission plan for its service area. A project sponsor that does not recover the investment cost through the access charge or is not reimbursed by the transmission owner is entitled to receive its share of the wheeling revenues, proceeds of the FTR auction and congestion revenues. Project costs for needed projects are added to the affected transmission owner's revenue requirement
PJM	Planning and expansion of the PJM transmission system occurs through the FERC-approved Regional Transmission Expansion Planning Process, which produces a single Regional Transmission Expansion Plan. Transmission owners pay for Network Reinforcements that resolve baseline network problems resulting from system changes such as load growth and recover the costs through FERC-filed transmission tariffs
New England (ISO-NE)	ISO-NE Transmission Plan coordinates regional transmission planning and results in the annual production of a 5-year plan of network upgrades for reliability, economic efficiency and generation interconnections, not otherwise proposed as merchant transmission facilities. A comprehensive transmission planning and expansion study occurs at least once every 3 years
New York (NYISO)	NYISO is required to undertake an annual review of the NY bulk transmission system and develop a comprehensive Area Transmission Review at least once every 5 years. The NY Public Service Commission also requires that the NYISO prepare illustrative transmission reinforcement options and cost estimates on congested paths to facilitate evaluation by transmission customers and owners
Texas (ERCOT)	ERCOT annually files a long-term operations plan including an overview of major systems and a 5-year plan

transmission upgrades beyond those necessary for interconnection. These generators can bid to sell energy at their location, or pay congestion charges to transmit it to another location. The decision on economic expansion rests on the costs and risks of the investment outweighing expected congestion charges.

However, because the facility owner is not necessarily the party paying congestion charges, and may in fact benefit from high congestion charges through ownership of FTRs, the transmission provider may have difficulty obtaining consent and funding from enough users to initiate and complete economic transmission upgrades. New high-voltage lines can instead be constructed as ‘merchant’ facilities, whereby market participants (or private investors) contribute to the construction cost in exchange for new transmission rights (or a return on investment), but very little of this type of investment has occurred.

3.8. Interconnection costs and charges

Interconnection costs and charges can greatly affect generation development because low (high) charges encourage (discourage) interconnection by generators. Table 8 summarizes interconnection costs triggered by and charges to a transmission user. Allocation of interconnection costs generally follows the ‘user pays’ principle, under which the beneficiary should pay for the costs of the interconnection. For instance, BC Hydro charges a customer triggering interconnection 100% of direct assignment facilities and a fair share of required network upgrades, defined as the total cost of the new facilities less the present value of 10 years’ of contribution to transmission margin, discounted at 13.5%. TransEnergie offers a \$522/kW credit against network integration costs, equivalent to the net present value of the rate paid by a network user over a 20-year period, net of 15% to account for operations and maintenance costs. In Ontario, monthly line and transformation connection charges apply to customers who have not paid the full costs of their interconnection facilities. In Alberta, interconnection customers pay 50% of the system expansion cost and 100% of the radial addition, while loads pay 50% of the system expansion cost.

3.9. Retail access

Table 9 summarizes the status of retail access by transmission design. Most utilities with retail access programs, whether operating under an open-access or a pool design, have a ‘price-to-beat’ service in which the retail customer does not take direct transmission service but instead schedules its generation source through the local distribution company (LDC). The customer then receives a bill credit against the energy portion of its bundled retail service equal to the regulated price-to-beat. The competitive generation owner also uses transmission service to schedule its output to the LDC on behalf of the retail customer.

In pool designs with electricity deregulation, a retail end-user can use the ISO/RTO tariff for procuring for its electrical needs through a scheduling coordinator (SC) that exactly passes through the ISO/RTO charges. Some very large retail customers do take direct transmission service, either scheduling bilateral transactions under an open-access tariff or acting as their own SCs under a pool design. For example, BPA offers direct transmission service to a small number of industrial customers (mostly aluminum smelters) and government agencies under the same open-access tariff used by all BPA customers. In Ontario, industrial or commercial customers with average monthly demands exceeding 5 MW have direct access to the energy pool as market participants.

Table 8
Summary of interconnection costs and charges by jurisdiction

<i>Canadian provinces</i>	
BC Hydro	Transmission service interconnections pay for 100% of direct assignment facilities and their share of required network upgrades
Alberta	Interconnection customers pay 50% of the system expansion cost and 100% of the radial addition. Loads pay 50% of the system expansion cost
Ontario	The costs of maintaining and operating the grid are recovered by Hydro One. Monthly line connection and transformation connection charges (for assets that connect the delivery point to the network lines and substations) apply to customers who do not own or have not contributed fully toward connection and transformation costs at the delivery point
Quebec	The discounted total costs incurred by the transmission provider should not, for each project, exceed the discounted value, over a 20-year period, of the point-to-point rate, less 15% to account for the present value of 20 years of operations and maintenance costs, as well as 0.64% to account for applicable capital tax. The transmission provider will assume the total cost of connection up to \$522/kW
<i>Pacific Northwest open-access designs</i>	
Bonneville Power Administration (BPA)	Transmission service interconnections pay for 100% of direct assignment facilities and their share of required network upgrades. Customers have the option of expediting the process by agreeing to pay all interconnection and upgrade costs
Puget Sound Energy	Transmission service interconnections pay for 100% of direct assignment facilities and their share of required network upgrades. Customers have the option of expediting the process by agreeing to pay all interconnection and upgrade costs
Portland General Electric	Transmission service interconnections not related to new generation pay for 100% of direct assignment facilities and their share of network upgrades. Customers have the option of expediting the process by agreeing to pay all interconnection and upgrade costs. Generators pay for all interconnection facilities, including network upgrades, but they receive a credit equal to the cost of network upgrades that can be applied to network or PTP service
<i>US pool designs</i>	
California	Interconnection customer pays for direct assignment facilities and reliability upgrades necessitated by the interconnection, net of any facilities already approved as part of the ISO grid expansion plan
PJM	Interconnection customer pays for the minimum upgrades necessary for accommodating their requests
New England (ISO-NE)	Interconnection customer pays direct assignment facilities, and an 'appropriate share of the cost of any required Network Upgrades'
New York (NYISO)	Interconnection customer pays direct assignment facilities, and an appropriate share of the cost of any required additions or upgrades
Texas (ERCOT)	The Transmission Service Provider applies to have the full costs of the transmission interconnection facilities included in its cost of service. To the extent that the Texas PUC does not allow the full amount, the interconnection customer reimburses the transmission provider for the difference

4. Conclusion

A transmission tariff survey can be used for many practical purposes. Our example is based on BCTC, a recently formed Crown corporation with the responsibility to operate, plan, and maintain BC Hydro's transmission system. BCTC was created as a separate company from BC Hydro, in response to the provincial government's 2002 Energy Plan [21]. By statute, BCTC was required to file with its regulator,

Table 9
Summary of retail access status

<i>Canadian provinces</i>	
BC Hydro (open-access)	No retail access currently allowed. The Energy Plan calls for direct access for large industrial customers. Access will be developed in conjunction with a form of stepped rate that both preserves the heritage benefits and allows for direct access
Alberta (pool design)	All end-use customers can choose to take default supply from the distribution company at the average pool price, or can purchase directly from the pool or bilateral market
Ontario (pool design)	Ontario has embedded and direct-connect retail customers. Hydro One Networks' core retail customers have unbundled transmission rates, but do not have direct access to the energy pool. Direct customers (industrial or commercial customers with average monthly demands exceeding 5 MW) connected to the low-voltage system have separate retail rates and have direct access to an energy pool as market participants. Retail competition has slowed down since the Government froze the price of electricity at 4.3 cents per kWh in Nov 2002, retroactive to May 2002, for customers using less than 250 MWh per year
Quebec (open-access)	No retail access currently allowed
<i>Pacific Northwest open-access designs</i>	
Bonneville Power Administration (BPA)	Historical direct service industries (e.g. aluminum smelters) are BPA transmission customers under the same rate schedules as wholesale transmission customers
Puget Sound Energy	Large industrial customers taking power under market rates as of March 9, 2001, who have paid transition payments to PSE, were eligible to self-supply power or purchase from other suppliers under a minimum 5-year contract. Under one version of the tariff, PSE continues to provide transmission services and charge the customer for transmission and ancillary services. Under another version, the customer or its agent schedules transmission service in addition to supplying power
Portland General Electric	Large non-residential customers (annual load > 1 MWa) may choose direct access for a minimum 5-year term for electricity supply and transmission service. These customers agree to one-time settlement of any difference between the cost of PGE generation resources previously used to serve them and the forward market price of an equivalent amount of power ('resource valuation mechanism')
<i>US pool designs</i>	
California	Retail competition introduced in March 1998 and then withdrawn in February 2001. Large consumers were allowed to contract directly with generators using bilateral contracts. The utilities indexed the amount of shopping credit direct access customers received to the PX market price. Customers could negotiate with third-party suppliers to lock in savings vis-à-vis the PX index price
PJM	End use customers' rates for transmission service are different for each state within PJM. Auction revenue rights reassigned as load switches between load-serving entities within the planning period PECO (Pennsylvania): 'price to compare' based on forward-looking generation and transmission rate quotes in unbundled tariff. PECO's rates for energy and capacity and transmission are avoidable if customer chooses another supplier. Competitive Transition Charge, which recovers stranded costs, is not bypassable PEPCO (Maryland): 'price to compare' is annual historical average of a customer's generation and transmission charges New Jersey: 'price to compare' based on annual statewide auction process for standard offer customers
New England (ISO-NE)	No specific retail transmission service. Massachusetts, Connecticut, Maine, New Hampshire and Rhode Island have instituted retail customer choice programs with 'price to compare.' Connecticut Light and Power customers can shop for generation service, but still receive transmission and distribution from the utility. Customers pay a Competitive Transition Assessment, which is adjusted annually, to reflect stranded costs

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Table 9 (continued)

New York (NYISO)	Most utilities have unbundled retail tariffs (Central Hudson, Consolidated Edison, NY State Electric and Gas, Niagara Mohawk, Orange and Rockland). Customers received a bill for the transmission component of their retail access service. Long Island Power Authority provides a bill credit to Choice Program participants to reflect LIPA's energy and capacity savings, embedded ancillary services and embedded charges for transmission service
Texas (ERCOT)	An affiliated Retail Electric Provider (REP) of an investor-owned utility is required to offer customers in its affiliated utility's service area a 'price to beat.' The REP cannot adjust this price for 3 years or until 40% of the customers in its affiliated utility's service area have switched to a competitive service provider. Each area of Texas also has a designated provider of last resort

the BCUC, no later than December 31, 2004; an application for its own open-access transmission tariff to replace BC Hydro's existing Wholesale Transmission Tariff (WTS).

Like most other systems in the Pacific Northwest, BCTC initially offered transmission services under an open-access design through BC Hydro's existing WTS tariff. This design allowed BC Hydro to keep rates low for its loads within BC by facilitating its access to export markets to earn trade revenues, while providing open and comparable access to third parties. As a new, independent transmission operator, BCTC sought possible improvements to the existing tariff design by drawing on the experience of other jurisdictions. At the same time, BCTC was guided by the goals and policy actions set forth in the Energy Plan, such as improving transmission access opportunities for independent power producers and facilitating retail access for large industrial customers, while safeguarding the benefits that domestic ratepayers have realized through trade.

To develop a new tariff to meet its (sometimes conflicting) goals, BCTC began by selecting an open-access design rather than a pool design, reflecting the market reality that the Order 888 pro forma tariff is well understood in the industry and is the principal design used for wholesale electricity trading in the Pacific Northwest. Within the framework of that primary design, BCTC sought to make improvements to the tariff to enhance access. The survey was useful to BCTC in developing potential proposals, both in terms of identifying and assessing practices that had been used elsewhere or, more commonly, to illustrate where no solution to a commonly faced issue had yet emerged.

Without a dramatic departure from the open-access design, BCTC [22] has proposed a number of modifications to help improve the tariff and meet the Energy Plan's goals. In the course of examining its options, BCTC found that understanding the structure and goals of the pool designs was also helpful. For example, while BCTC's proposed tariff does not include locational marginal pricing that might encourage generators to locate downstream of a congested interface or signal the value of new transmission investment, it does contain two features that in some senses mimic the operation of a pool design:

- A locational credit based on the value of deferring a transmission upgrade. The deferral credit is tied to specific transmission investments in BCTC's 10-year capital plan that can be deferred through redispatch of generators on either side of the constraint.
- A formula-based price for short-term PTP service based on the difference between market prices in Alberta and Mid-Columbia to improve utilization and facilitate trading.

In addition, understanding experiences in various jurisdictions helped to inform other elements of BCTC's proposed OATT. For example, concerns about limited transmission investment under a strictly

queue-based transmission tariff prompted BCTC to propose an Open Season process, in which individual transmission requests can be aggregated to facilitate new transmission investment. Similarly, well understood concerns about imposing a reservation-based tariff on low capacity-factor generating facilities, such as wind or small hydro, prompted BCTC to propose a new long-term firm point-to-point rate for so-called ‘BC Clean’ generators with maximum output of less than 50 MW. This proposed new service uses a tiered rate structure, under which service up to the facility’s annual capacity factor is priced at BCTC’s standard long-term firm PTP rate, while service beyond that level is priced at BCTC’s rate for short-term PTP service.

In short, studying what is actually done elsewhere, in addition to understanding the theoretical underpinnings of transmission rate design, is of considerable value to a transmission provider seeking to update their tariff design.

Acknowledgements

The views in this paper are not necessarily BCTC’s, and the proposals described above are before the regulator in BC at the time of this writing. We thank C.K. Woo for his valuable editorial comments. Without implications, all errors are ours.

Appendix A. Sample of 12 transmission tariffs

- (a) Alberta Electric System Operator. 2003 General Tariff Application Negotiated Settlement Agreement, (November 4, 2003). Available at web.taalberta.ca/tar/index_tar.asp
- (b) Bonneville Power Administration Transmission Business Line. 2004 Transmission and Ancillary Service Rate Schedules (effective October 1, 2003); Open Access Transmission Tariff (effective October 1, 2001). Available at www2.transmission.bpa.gov/
- (c) California ISO Conformed Tariff (amended as of October 8, 2003). Available at www.caiso.com/pubinfo/tariffs/
- (d) Federal Energy Regulatory Commission. Pro Forma Open Access Transmission Tariff. Available at www.ferc.gov/legal/ferc-regs/land-docs/rm95-8-0aa.txt
- (e) Hydro-Quebec TransEnergie. Hydro-Quebec Open-Access Transmission Tariff (April 2003). Available at www.transenergie.com/oasis/hqt/en/entree.htmlx
- (f) New England Power Pool, Restated NEPOOL Open-Access Transmission Tariff (amended as of Feb. 14, 2003); available at www.isone.com/FERC/filings/Index_NOATT.html. See also Market Rule 1; available at www.isone.com/smd/market_rule_1_and_NEPOOL_manuals/Market_Rule_1
- (g) New York Independent System Operator, Inc. FERC Electric Tariff, Original Volume No. 1, Open-Access Transmission Tariff (amended as of October 1, 2003). Available at www.nyiso.com/services/oatt.html
- (h) Ontario Energy Board. Ontario Transmission Rate Schedules (issued April 30, 2002). Also see Independent Electricity Market Operator. Market Rules. Available at www.theimo.com/imoweb/manuals/marketdocs.asp
- (i) PJM Open Access Transmission Tariff (amended as of September 22, 2003). Available at www.pjm.com/documents/ferc.html

- (j) Portland General Electric Company. Pro forma Open Access Transmission Tariff, Second Revised Volume No. 8. (Schedules 1–6 effective February 1, 2002; Schedules 7–9 and Attachment H effective November 1, 2001, remainder of document effective April 2, 2001), available at oasis.portlandgeneral.com Schedule 483: Transmission Access Service Large Non-residential (effective August 29, 2003); Schedule 58: Direct Access Service Large Non-residential (effective February 5, 2003); Schedule 125: Resource Valuation Mechanism, (effective August 29, 2003). Available at www.portlandgeneral.com/about_pge/regulatory_affairs/tariffs/rate_schedules.asp#transmission
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- (l) Texas Public Utility Commission. Chapter 25: Substantive Rules Applicable to Electric Service Providers, Subchapters I and J (amended as of Dec. 1, 2003). Available at www.puc.state.tx.us/rules/subrules/electric/index.cfm; See also The Electric Reliability Council of Texas, Inc. (ERCOT). Market Rules. Available at www.ercot.com/AboutERCOT/PublicDisclosure/ProtocolRev.htm; See also Texas PUC Docket No. 22052. Order on Rehearing Approving the Standard Generation Interconnection Agreement.

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