OPEN TRANSMISSION ACCESS: A STRATEGY TO FACILITATE OPEN ACCESS AND PROMOTE THE EFFICIENT USE OF THE BC TRANSMISSION SYSTEM

by

Stephen Tran
B.Sc., University of Alberta, 1988

PROJECT SUBMITTED IN PARTIAL FULFILLMENT OF THE REQUIREMENTS FOR THE DEGREE OF

MASTER OF BUSINESS ADMINISTRATION
EMBA Program

in the

Faculty of

BUSINESS ADMINISTRATION

SIMON FRASER UNIVERSITY
August 2004

APPROVAL

Name: Stephen Tran

Degree: Master of Business Administration

Title of Project: Open Transmission Access: A Strategy to Facilitate Open Access and Promote Efficient Use of the BC Transmission System

Supervising Committee:

Dr. Steven Globerman
Senior Supervisor
Adjunct Professor
Faculty of Business Administration

Dr. Neil Abramson
Second Reader
Associate Professor
Faculty of Business Administration

Date Approved: August 10th, 2004

ABSTRACT

The purpose of this paper is to provide an in-depth analysis of the Wholesale Transmission Services Tariff, and to evaluate and recommend alternative policies and business practices that can be adopted to facilitate open access and promote efficient use of the BC transmission system.

An electric transmission system has large minimum efficiency scale and enormous overall economies of scale. It is imperative that transmission system planning must be proactive and forward-looking in order to take advantage of the benefits of economies of scale. Economies of scale along with the unique characteristics of a dynamic AC grid, where benefits and beneficiaries of an upgrade are many, difficult to identify, change over time and widely used, make it difficult to assign costs of network upgrades to specific uses or users. In this context, average incremental cost pricing is suited for long-term transmission services. On the other hand, when there is insufficient capacity to accommodate both the utility's and its competitor's energy transactions, or when they are competing for the same sale, an auction process may be used to discover the true value of the scarce transmission capacity.

In addition, access to scarce transmission capacity should be granted to whoever can produce the power most efficiently at any given time. This approach will create a level playing field for all generators. It will ensure that only the most efficient generation is deployed to serve load.

DEDICATION

To my family, Dao, Andrea, Pamela and Jessica, for their patience, support, and understanding throughout my two years in the Executive MBA program.

ACKNOWLEDGEMENTS

I would like to thank BC Hydro and BCTC for providing financial support, and my friends and colleagues for offering their assistance and feedback. In addition, I wish to extend my thanks to my senior supervisor, Dr. Steven Globerman, for his insight and guidance throughout this project.

TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

GLOSSARY OR LIST OF ABBREVIATIONS AND ACRONYMS

AIES	Alberta Interconnected Electric System
BC	British Columbia
BCTC	British Columbia Transmission Corporation
BCUC	British Columbia Utilities Commission
FERC	Federal Energy Regulatory Commission of the United States
IPP	Independent Power Producer
ISO	Independent System Operator
kV	Kilovolt
MW	Megawatt
NOPR	Notices of Proposed Rulemaking
OASIS	Access Same-Time Information System
RTO	Regional Transmission Organization
SIS	System Impact Study
SMD	Standard Market Design
SPA	System Performance Assessment
TSP	Transmission Service Provider
TSBU	Transmission Strategic Business Unit
U.S.	United States of America
WTS	Wholesale Transmission Services Tariff

1 INTRODUCTION

1.1 BC Transmission System

In 1962, the British Columbia (BC) provincial government amalgamated BC Electric, which the Province had purchased a year earlier, with another Crown Corporation, BC Power Commission, to create a new Crown Corporation, BC Hydro. The corporation was involved in the tripartite negotiation of the international Columbia River Treaty among the British Columbia, Canadian and American governments. This treaty required Canada to provide storage in the Columbia River basin by building a number of dams on the Columbia River, on the tributaries of the Kootenay River, and near the outlet of the Arrow Lakes. It also obligated the United States (U.S.) to build a series of dams on the Columbia River to make the most effective use of the improvement in stream flow. The release of water over the dams in both countries was to be regulated and co-ordinated between the countries. This treaty was ratified in 1964, and BC Hydro was assigned the responsibility of implementing the treaty.

In addition to the benefit of flood control, the regulation of water flow over the dams could also be used to generate electricity. During the 1960's and 1970's, BC Hydro took on some of the most ambitious hydroelectric construction projects in the world in part to implement the Columbia River Treaty. The initial two phases of this work brought on stream 681MW of generation on the Peace River, and 870MW on the Columbia River. To bring this power to serve loads in the Lower Mainland, BC Hydro pioneered the use of high-voltage transmission systems as it built a number of 500 kV transmission lines from the Peace Region and South Interior to the load centres. Today, BC Hydro owns a network of 18,000km of 60 kV to 500 kV transmission lines connecting BC Hydro's approximately 12,000MW of generation, independent power producers (IPPs), large users, BC Hydro's load centres, and other utilities in the Province.

The BC Transmission System has two 500 kV lines in the Greater Vancouver area, and one 230 kV line in the East Kootenay area. These lines connect the BC Electric System with the Bonneville Power Administration System. It also has one 500 kV line, one 144 kV line, and two 138 kV lines connecting with the Alberta Interconnected Electric System. These connections allow electric energy trades across Alberta, BC and the U.S. to occur. In 2003, there were almost 88,000 energy transactions using the BC Transmission System to move approximately 21,000,000MWH of electric energy worth approximately $800 million[1].

BC Transmission System has been planned and built to facilitate maximum generation operating flexibility and have sufficient margin to serve load growths. More importantly, the transmission system has been built to serve winter peak loads that occur over a few hours per year. Other times of the year, the system loads may be as low as 40% of the winter peak. The spare capacity during these periods is used to accommodate spot-market energy transactions.

[1] This value has been estimated based on average Mid-Columbia prices.

No other major transmission facility has been built in more than a decade to provide additional capacity. In the meantime, the transmission system load has been steadily increasing and taking up all available capacity. Nowadays, there are many possible congestion paths[2] in the system that once had plenty of spare capacity (Figure 1-1). In order to accommodate a new long-term transmission service request, expensive network upgrades are required.

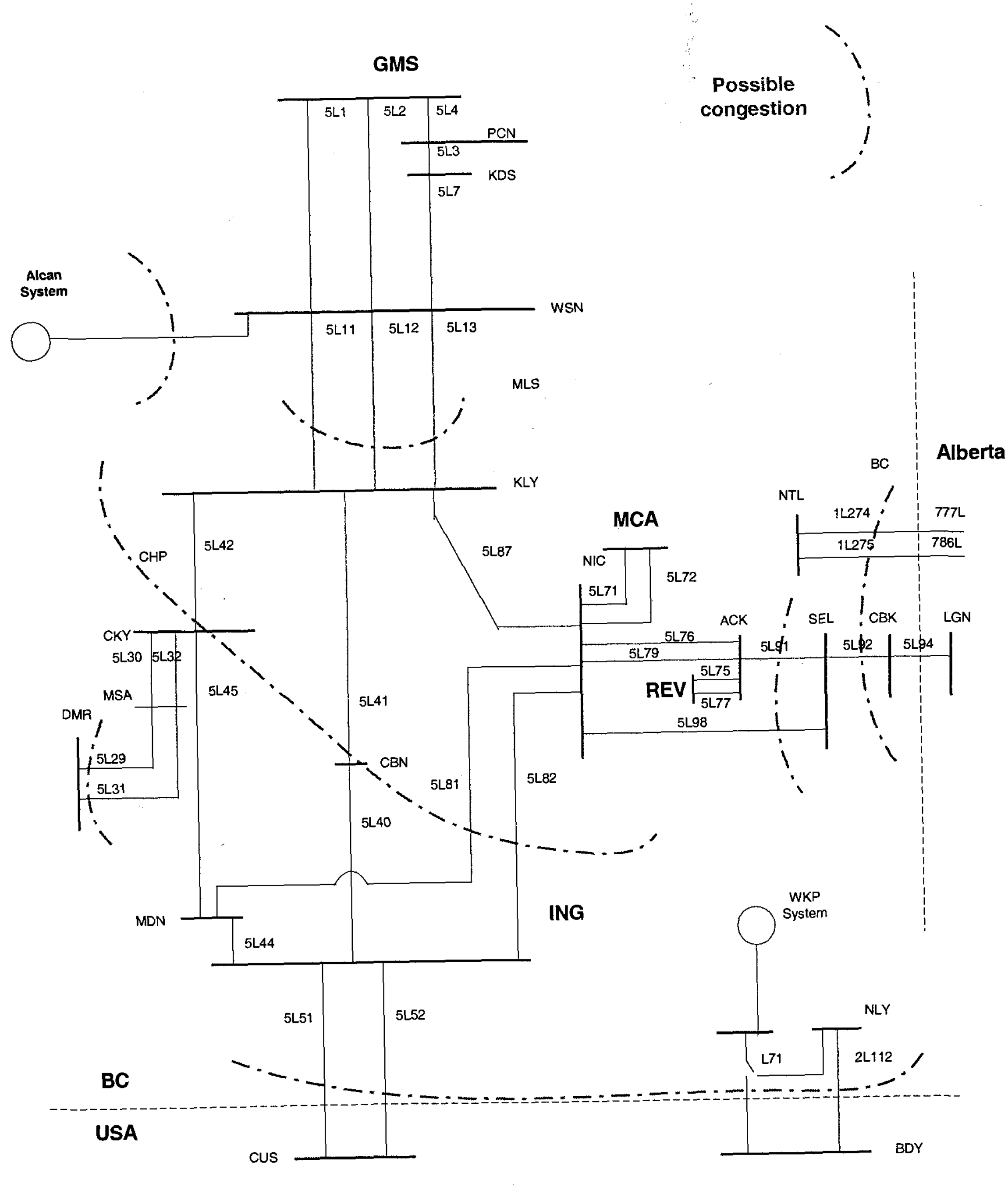
1.2 British Columbia Transmission Corporation

In November 2002, the British Columbia provincial government released a new energy policy called the Energy Plan[3]. Through this policy, the Province hopes to encourage, among other things, the development of a vibrant IPP industry in BC. IPPs will be allowed to compete with BC Hydro in serving large industrial and commercial electricity users in the Province. To compete fairly with BC Hydro, IPPs need non-discriminatory access to the transmission system. It is generally believed that an independent Transmission Service Provider (TSP) is required and is essential to facilitate the competition.

To promote open competition upstream, the provincial government enacted legislation to create an independent TSP: the British Columbia Transmission Corporation (BCTC). BCTC, a provincial Crown Corporation was formed on May 29, 2003 under the Transmission Corporation Act[4]. With a separate and independent Board of Directors,

[2] A congestion path means the schedule of movement of electric energy on a path consisting of a line or a group of lines exceeds the capability of that path.
[3] The Province of British Columbia, Energy for Our Future: A Plan for BC, November 2002
[4] The Province of British Columbia, Transmission Corporate Act - Bill 39, May 2003

Figure 1-1: BC Bulk Transmission System & Possible Congested Paths



BCTC began operation on August 1, 2003.

BCTC's mandate is to manage, maintain, plan and operate BC Hydro's transmission assets, and provide open and non-discriminatory access to the BC Transmission System. BCTC also provides ancillary services that are required to support basic transmission services. In addition, BCTC is the BC Control Area operator responsible for the reliable and safe operations of the BC Electric System and for the scheduling of power flows between control areas[5], generating plants and load centres within BC.

With its Head Office in Vancouver BC, BCTC has one system control centre and four area control centres. These centres operate twenty-four hours a day, seven days a week. BCTC employs approximately 325 managers, professionals and business support employees across the Province. Most of BCTC's staff were transferred from BC Hydro's Transmission Line of Business on the first business day.

BCTC is a regulated utility under the British Columbia Utilities Commission's jurisdiction. As such, BCTC's revenue is set based on the forecast cost of service. During the transition period of the first couple of years, BCTC's operations will be fully funded by BC Hydro under contract to operate and manage the BC Transmission System, and provide transmission services on BC Hydro's behalf. Beginning April 2005, BCTC will have its own approved cost structure for its operations. Based on the most recent

---

[5] Control area: means the electric system or systems within a given area, bounded by interconnection metering and telemetry, having one operator responsible for effecting generation control to maintain the area's interchange schedule with other similar areas and contributing to frequency regulation of an interconnection system. Control area can correspond to the boundaries of a single utility or of several utilities. BC Control Area includes BC Hydro System and Aquila System.

forecast, BCTC's F2006 revenue will be approximately $708 million. This annual revenue is intended to recover the following forecast costs:

Table 1-1: BCTC's F2006 Cost Structure[6]

Cost of Service	$000
BC Hydro's Charges	509.4
Operating, Maintenance & Administration	169.9
Cost of Market-domestic	5.8
Asset Related Expenses	
Finance Charge	1.7
Depreciation & Amortization	16.7
Grants & Taxes	0.3
Allowed Return	3.9
Total	707.6

Of this $708 million annual revenue, $123 million is derived from generation related transmission assets, substation distribution asset management and others services. The remaining $585 million comes from transmission services.

1.3 Regulatory and Political Environment

There is a perception in the industry that BCTC has been created to facilitate the expansion of privately funded generation projects within BC. This perception suggests that BCTC's success or failure will be measured by the quantity of IPP projects. However, non-discriminatory transmission access is only one of many factors influencing the development of competition. It can be assumed that BCTC will take actions to ensure

[6] BC Hydro, BC Hydro 2004/2005 & 2005/2006 Revenue Requirement Application, December 2003

that transmission access is not a constraint to IPP development, but it is unreasonable to expect BCTC will be able to single-handedly change IPPs' profitability or the demand for their production.

In addition to facilitating the competition for supplying the electric energy by the private sector within BC, BCTC has been given the mandate to maintain, if not increase, BC's benefits from trading activity in the U.S. wholesale power market. This expectation requires BCTC to operate in such a way that meets regulatory requirements in British Columbia as well as in the U.S. The requirement to meet regulations in the U.S., and the current level of opposition to privatization in BC, have caused concern among the public that BCTC has been established to privatize and/or weaken the Province's control of its transmission system.

BCTC's business model contrasts significantly with those of the participants in the U.S. power market. In Chapter Four, it will be demonstrated that this difference requires BCTC to make changes to its transmission access policies if it hopes to fulfil its given role.

Therefore, any strategy implemented by BCTC must not impede the development of competition in energy production within BC, or the ability of BC entities to transact in the U.S. wholesale market. At the same time, BCTC must demonstrate its effectiveness in controlling the BC Transmission System to create benefits for the people of BC.

1.4 BC Transmission Services

BCTC offers two basic electric energy delivery services and seven ancillary services that are required for co-ordination of the delivery among the interconnected systems, and for safe, reliable operations. These services are offered under the Wholesale Transmission Services Tariff (WTS)[7].

The two basic electric energy delivery services are Network Integrated Transmission Service (NITS) and Point-to-Point (PTP) Transmission Service. NITS is intended for third-party electricity service providers who have multiple loads and generation resources connected to the host utility's transmission grid at different connection points. This service is most suitable to customers whose loads at each location vary throughout a scheduling hour. Typical NITS customers are municipal utilities who may have several generators connected to a larger utility's transmission grid. Since municipal utilities are serving mostly residential, commercial and, to a lesser extent, small industrial customers, their total loads at various points are changing widely over the day and are difficult to predict accurately. Predicting the total load, on the other hand, is an easier task. NITS requires customers to submit energy schedules for serving the total load but not schedules for individual points; it provides more flexibility to customers for using all their generators to meet their total power requirements.

PTP Transmission Service is available in three forms, long-term firm[8], short-term (less than a year) firm, and short-term non-firm[9] services. PTP Transmission Service can

[7] BC Hydro, Wholesale Transmission Service Tariff, June 1997
[8] Firm service is provided on a basis comparable to TSP's Native Load.
[9] Non-firm service is provided on an as available basis. It is provided using idle capacity.

also be used for multiple points of delivery (loads) and multiple points of receipt (generation resources), but it is more suitable and economical if load levels at each point of delivery are predictable and somewhat constant over a scheduling hour.

Transmission services are provided on a first-come, first-served basis. Services must first be reserved on the Access Same-Time Information System (OASIS) in accordance with strict timelines from at least 60 days in advance to one hour ahead. Once a reservation has been made, customers may submit energy schedules for real-time delivery. Energy scheduling activities are conducted based on standard industry practices. Other than short-term services, provided on as available basis, BCTC will undertake transmission network upgrades to accommodate new requests for NITS and long-term firm PTP. Quality and priority of service are as shown in Table 1-2.

Table 1-2: Quality and Priority of Wholesale Transmission Services

Transmission service	Quality	Priority[10]
NITS	Firm	1
Long-term Firm PTP	Firm	1
Short-term Firm PTP	Firm	1
Network Economy	As Available	2
Short-tem Non-firm PTP	As Available	3

The seven ancillary services are:

- Scheduling, System Control and Dispatch Service: is required to schedule the

[10] Priority 1 is the highest. It is used to determine the order of curtailment after the request for service has been accepted.

movement of power through, out of, within, or into a Control Area;

- Reactive Supply and Voltage Control Service: is required to maintain transmission voltages on the system within acceptable limits;
- Regulation and Frequency Response Service: is for the continuous balancing of resources (generation and interchange) with load and for maintaining scheduled Interconnection frequency at sixty cycles per second (60 Hz);
- Energy Imbalance Service: is provided when a difference occurs between the scheduled and the actual delivery of energy to a load located within a Control Area over a single hour;
- Operating Reserve – Spinning Reserve Service: is needed to serve load immediately in the event of a system contingency;
- Operating Reserve – Supplemental Reserve Service: is needed to serve load within a short period of time; and
- Loss Compensation Service: is available for making up real power losses.

Except for Loss Compensation, BCTC must make available these ancillary services to customers for supporting their energy transactions. Under WTS, although customers must take the first three of these services from BCTC, they may choose to self-supply the other requirements. Customers may make this choice as often as they wish. BCTC must procure these services from other service providers in advance, but it has no certainty when and how much customers will buy. The flexibility enjoyed by customers increases risk for BCTC.

1.5 BC Transmission Customer Segments

Currently, BCTC has approximately 24 active customers, with 83% of its revenue contributed by a single large customer. Serving in excess of 90% of the BC market, BCTC provides transmission services to BC electric utilities, IPPs, large industrial customers, and energy marketers who export to and import from Alberta and the U.S.:

- Electric Utilities: are the incumbent electricity service providers. These customers purchase both NITS directly or indirectly from BCTC. In addition, they also utilize PTP Service for serving their retail loads.

- Energy Marketers: operate from BC, Alberta and the U.S. The energy marketers transact inter-provincially and internationally. These customers purchase PTP Transmission Service for exporting to and importing from Alberta and the U.S. They also use this service for moving energy between Alberta and the U.S. markets. With the introduction of the new Energy Plan, energy marketers will have more opportunities for selling their services to large retail customers in direct competition with the electric utilities. They will also be able to sell their marketing expertise to IPPs.

- Independent Power Producers: These customers currently sell almost all their output to BC Hydro. Currently, these customers mainly use interconnection service from BCTC. Occasionally, they may sell their excess energy to the spot markets directly or through their agents. Under the new Energy Plan, independent power producers will have the opportunity to sell directly to retail load within BC.

- Large Users: connecting directly to the transmission system, these customers will be permitted to purchase electric energy from alternative sources other than their host utilities. They may do so by acquiring transmission services directly from BCTC or through the energy marketers.

1.6 Strategic Issue

Over the past few months, BCTC has consulted with many key stakeholders, and performed a thorough self-assessment based on stakeholder feedback, as well as a detailed analysis of its core business. Through these efforts, BCTC has set its mission to facilitate open access and promote efficient use of the BC transmission system. This intent is clearly evident in BCTC's Mission Statement:

> We are an independent electric transmission company that manages the energy highway, providing timely and non-discriminatory access to the grid in BC. We create value for our customers by providing safe, reliable and cost-effective transmission services while respecting the diverse needs of all our stakeholders.[11]

BCTC currently operates BC Hydro's WTS. This tariff specifies rules and procedures that both the TSP and the customer must follow for arranging transmission services. However, these rules and procedures were originally designed by the Federal Energy Regulatory Commission of the United States (FERC) for a different electric industry structure.

[11] BCTC, Board of Directors Strategy Retreat, April 2004

BC Hydro's WTS has been in operation since 1997. It will be shown that this tariff is inefficient and not user-friendly based on past experience. The transmission service procurement rules and procedures are cumbersome and create uncertainties for the transmission system planning process. These issues will be discussed in detail in Chapter Four. To ensure success in accomplishing its mandate, BCTC will need to consider alternative policies and business practices.

1.7 Methodology

The purpose of this paper is to provide an in-depth analysis of the WTS, to identify impediments to BCTC's objectives, and to evaluate and recommend alternative policies and business practices that BCTC can adopt to facilitate open access and promote efficient use of the BC transmission system. Chapter Two provides a brief description of the overall electricity industry. This description shows the relationship among the industry's four components. It then discusses recent changes in the electric industry in North America and BC that have led to the creation of a stand-alone transmission service industry.

Chapter Three discusses generic access issues in detail. Chapter Four provides a detailed analysis of the WTS the impediments created by existing rules and procedures in order to illustrate the challenges facing the BC transmission industry. Chapter Five identifies and evaluates alternative policies and business practices adopted in other jurisdictions. Following this analysis, Chapter Six evaluates and recommends policies and business practices that best support BCTC in fulfilling its mission. A summary of the main findings and recommendations is provided in the final chapter.

2 INDUSTRY ANALYSIS

2.1 Transmission Service Industry

Traditionally, transmission service is offered as part of a bundled service provided by an integrated electric industry. The bundle consists of generation, transmission, distribution, and customer services. However, not all customers need all services. Some large customers can modify their demand over time and can directly affect electric energy production and delivery costs. In the early 1990's, large users started to demand more service options. For example, they demanded that utilities offer unbundled products and services. That is, they demanded that utilities price generation, transmission, distribution and customer services separately. Gradually, some utilities added more service options including stand-alone transmission service. For example, TransAlta Utilities began to offer Network Transmission Service to its large industrial customers and municipal utilities in 1994. This trend, and changes in regulation and market conditions, has created a new transmission service industry in North America and elsewhere.

Before taking a closer look at the transmission service industry, a brief description of the electricity industry is warranted. This description provides an overall picture that shows the linkage between transmission service and other electricity production and delivery processes, as well as how electricity is brought to our homes. More importantly, it provides a road map showing how the electricity industry is changing from monopolistic to competitive with transmission playing the facilitating role. As such, any policy proposed for transmission access must be designed to avoid interference with the competitive process.

2.2 Electricity Industry

Electricity service is essential in our modern economy. In addition to being a source of energy, electricity is critical for maintaining security and order within our society. The attention that the Canadian and American governments paid to the Northeast blackout event on August 14, 2003 demonstrates the importance of electricity to our society and the reliance we have upon it. We have come to expect the service to be available instantly and on demand. Other than on a few rare occasions, the electricity service providers continue to meet our expectations every time we turn on a switch despite the complexity in operating an intricate network of production machines and delivery systems.

The electricity industry consists of four distinct functions that make electricity available for use. These functions are generation, transmission, distribution, and retail service.

2.2.1 Generation

Generation is the production of electricity. It is the process of converting one form of energy into electric energy. The most common forms of energy used for this conversion process are hydraulic kinetic energy and thermal energy created, for example, from burning fossil fuels. In the past, economies of scale dictated the need for building large generating plants that required long lead-times and large capital investments. Large generating plants were normally located in remote areas where water and fossil resources were found. These requirements limited the investment opportunities to large corporations and public utilities. Small independent investors were unable to compete. For this reason, generation was considered a natural monopoly.

However, improvements in technology have made generation facilities smaller and more economical to operate. This allows small independent investors to get into the generation business. These developments have resulted in changes in regulation allowing competition in power generation. In recent years, over half of the new generating capacity in the U.S. has been built and owned by IPPs.[12] Also, most of the new generating plants that have been, and will be, constructed in BC are IPPs.

2.2.2 Transmission

The transmission system is a network of high voltage power lines connecting power generating plants in remote areas, where electric power is produced, to the distribution hubs near large load (consumption) centres spreading over a wide geographic area. Transmission systems have been built by integrated utilities to connect their respective generating plants and distribution centres in their service territories. Transmission systems are also used to provide delivery services to wholesale customers, such as municipal electric utilities, and large industrial customers.

To improve system reliability and efficiency, transmission systems are interconnected to provide mutual support and facilitate energy trades between integrated utilities. Today, transmission systems in North America are connected to form four

[12] Baumol, William & Sidak, Gregory , Transmission Pricing and Stranded Costs in the Electric Power Industry, the American Enterprise Institute, Washington, D.C., 1995

major interconnected systems: the Western Interconnected System; the Eastern Interconnected System; the Quebec Interconnection; and the Texas Interconnected System. Each interconnected system consists of a number of control areas. Power flows between control areas are closely regulated to ensure overall system integrity. The Province of British Columbia is a control area within the Western Interconnected System. The BC System, which consists of the BC Hydro System, the Fortis BC System and many privately owned (single-line) systems, has strong ties with Alberta and the U.S. Pacific Northwest.

Transmission service has also been considered a "natural monopoly". Facilities for building the transmission grid are lumpy. Transmission lines cannot be built one strand at a time to add just the right capacity for a customer. A transmission line, once built, adds hundreds of MW of carrying capacity to the system and can be used to serve many customers. Due to economies of scale, it is uneconomical and impractical to have multiple TSPs each building its own lines to compete for the same customers. For these reasons, transmission service continues to be regulated and is generally accepted to be a natural monopoly.

Transmission facilities can be classified in three categories: customer facilities; TSP interconnection facilities; and network facilities.

Customer facilities are those constructed, owned, maintained and operated in accordance with industry standards by the customer or by the utility at the customer's expense. These facilities usually include everything from customer's load or generator site to just outside the utility's substation fence.

TSP interconnection facilities are for the sole purpose of connecting the customer to the system. Interconnection facilities tie customer's facilities just outside the substation fence to the substation bus. These facilities are also referred to as Direct Assignment Facilities.

Network facilities are constructed, owned, maintained and operated by the utility for serving many customers. Network facilities are sub-categorized into regional and bulk systems. Regional systems usually consist of facilities operated at voltage of 161kV or below. Regional systems are constructed to meet local areas' loads. The bulk system is the main grid, the backbone of the transmission system. The bulk system consists of facilities operated at 230kV and up. (The highest voltage level in BC is 500kV). The bulk system connects all regional systems with multiple transmission paths to provide a high level of reliability and security.

2.2.3 Distribution

The distribution system consists of mostly radial low voltage (35kV and below) lines connecting the distribution hubs and electric energy users. These users include small-industrial, commercial and residential customers. The primary function of this system is to deliver electricity to consumers. Similar to transmission, distribution service continues to be provided by a single firm within a service territory.

2.2.4 Retail Services

Retail services traditionally were considered a part of the distribution function. However, the introduction of competition in the electric energy markets has made it necessary to separate the retail function from the distribution function. The retail function involves the marketing and selling of electric energy to consumers. This function includes metering, billing, and customer services.

2.3 Electric Utility

Electric utilities are described by one of the following three basic business models:

- Integrated utility: engages in generation, transmission, distribution and retailing services over a wide geographic area. It provides bundled services that include the production and delivery of power, as well as customer services to end-users. Some integrated utilities also serve distributors such as municipal utilities. Integrated utilities are owned and operated by governments or by private investors. In Canada, most of the major integrated utilities are Crown Corporations such as BC Hydro. A few investor-owned utilities exist in BC, Alberta and Nova Scotia. One example is Fortis BC;

- Municipal utility: owned and operated by a municipality such as the City of New Westminster, it engages in the distribution and retail functions. Municipal utilities usually purchase electric energy at wholesale from the integrated utilities for resale to consumers residing within their city boundary; and

- Co-operative or rural electrification association (common in Alberta and the U.S.): engages in the distribution and retail functions for the benefits of its members. Similar to the municipal utility, the association purchases electric energy at wholesale from an integrated utility for redistribution to its members.

2.4 Presumption of Natural Monopoly

In the past, all integrated electric utilities were shielded from competition by the exclusive right to serve in assigned service territories. It was believed that the electricity service involved economies of scale and economies of scope, and that there was only room in the market for a single electricity service provider of minimum efficient scale and scope. For these reasons, electricity service was considered a "natural monopoly", and the exclusive right to serve a given area was granted to a single firm. In exchange, integrated utilities had the obligation to serve and the responsibility for planning and constructing sufficient generation, transmission and distribution capacity to service existing and forecast demand in their respective service areas.

However, technological advances discussed earlier in this section have minimized the relevance of the natural monopoly model. Thus, competition in generation is now well established, and retail competition is being introduced in some jurisdictions such as California and Alberta.

Due to long lead-times, electricity production and delivery facilities are planned and built many years in advance. However, because of differences in actual and forecast demands, some utilities end up with more generation capacity than needed, while other areas with more load than is able to be served. In addition, different generation technologies are used throughout North America. The generation technology employed is dependent on locally available energy resources. For example, hydro plants are predominant in the Pacific Northwest, while thermal plants such as coal fired, gas or nuclear are more common elsewhere. Different technologies have different implications in the cost of supply leading to price disparities across North America. Table 2-1 reports the 1998 average prices per kWh (in ¢/kWh) for a sample of cities.

Table 2-1: 1998 Average Electricity Prices[13]

Utility	Residential	Small User	Medium User	Large User
Montreal	6.03	7.53	6.10	4.06
Toronto	9.23	10.16	8.20	6.35
Vancouver	6.12	6.70	4.56	3.23
Boston	15.97	17.54	12.86	11.29
Houston	11.95	10.49	8.27	5.41
New York	20.01	21.19	16.19	11.11
San Francisco	16.62	13.57	12.34	7.13
Seattle	5.90	5.23	4.93	4.87

Mismatches between supply and demand, as well as the price disparities, have created opportunities for wholesale electric energy trades among the utilities. Benefits from these trades were usually shared among the parties involved.

2.5 Recent Changes in the United States

This section begins with a discussion of recent and upcoming changes in the U.S. The discussion provides insight into the business and political reasons why the BC electric industry is changing.

2.5.1 Changes in Regulation

As discussed earlier, improvements in power generation technology are making it possible for small investors to participate in electric energy production, and to develop

[13] Hydro Quebec, Comparison of Electricity Prices in Major North Cities, May 1998, pg. 20

many small-scale power plants. To encourage the development of generation technologies that utilize renewable energy sources such as wind, solar and small hydroelectric, and that efficiently utilize fossil fuels, the U.S. Department of Energy introduced two regulations: the 1978 Public Utility Regulatory Policies Act (PURPA); and the 1992 Energy Policy Act. The PURPA required (forced) investor-owned utilities to purchase energy production from qualified generation facilities owned by IPPs at prices usually higher than the utilities' avoided costs. This exerted upward pressure on electricity prices in the short run, as utilities tried to pass on the higher costs to their customers. The net additional cost of service is equal to the amount of energy purchased multiplied by the difference between the purchased price of energy and the saving in incremental production cost.

The 1992 Energy Policy Act required utilities to provide IPPs access to their transmission systems. This increased IPPs' market opportunities, as IPPs now had more than one buyer. They could now sell their production to other electricity service providers across the country in direct competition with the integrated utilities for the same wholesale customers. However, IPPs must rely on the host utilities' and others' transmission systems for delivering electricity to their customers. Under this scenario, the integrated utilities had, or were perceived to have, unfair advantages, as they owned and operated the transmission systems.

Although the 1992 Energy Policy Act improved IPPs' ability to gain access to the transmission systems, generation competition did not thrive until 1996, when the Federal Energy Regulator Commission (FERC) introduced the Pro Forma Tariff.

2.5.2 Pro Form Tariff

In 1996, to encourage efficient inter-regional trades and fair competition in the wholesale electric energy markets, FERC introduced Order 888[14] and Order 889[15]. These two orders set out rules forcing investor owned electric utilities (IOUs) to open up their transmission systems and offer non-discriminatory transmission services. These services allow customers to wheel their energy from one location to another to directly serve wholesale loads in areas that were formerly the utilities' exclusive service territories.

All IOUs must comply with the FERC Orders. Adhering to the rules is the condition that utilities must meet before they are allowed to compete and sell their energy at market prices. However, FERC does not have jurisdiction over government owned, co-op, or Canadian utilities. To get around this limitation, FERC included the "Reciprocity" requirement in its Order 888. Non-jurisdictional utilities must have comparable, or the same transmission services before they are allowed to use investor-owned transmission systems and compete in the U.S. electric energy market. BC entities must therefore meet this Reciprocity requirement before they are allowed to participate.

Included in Order 888 is the Pro Forma Tariff, also known as the Open Access Transmission Tariff. The Pro Forma Tariff defines what transmission services an investor-owned utility must offer, along with terms and conditions for such services. It defines procedures and timelines that transmission service customers must follow for submitting service applications, and that TSPs must adhere to for processing those

[14] FERC, Order 888, April 1996
[15] FERC, Order 889, November 1997

applications. It is meant to set minimum standards however, utilities may implement other forms of transmission services that meet FERC's superiority test.

Order 889 defines further obligations for TSPs. These include an obligation for implementing an on-line web-based transmission service reservation system, the Open Access Same-Time Information System (OASIS). Order 889 sets out rules regarding how information related to the transmission system should be communicated to the market. That is, communication of the transmission information between the TSP and the customers must be conducted over OASIS. This includes the transmission capacity available, congestion information, the transmission system maintenance schedule, and the purchase and sale, as well as quantities and prices, of the transmission services. Order 889 is meant to ensure that all customers have access to transmission related information at the same time. Order 889 also defines Standards of Conduct for the TSPs. For example, it requires that the integrated utilities have functional separation. That is, the transmission function must be operated independently from the influence of the generation and marketing functions in order to ensure non-discriminatory transmission access.

The Pro forma Tariff does not make direct reference to generation interconnection procedures. However, when the industry encountered problems in dealing with applications for generator interconnection service and requested FERC to rule on matters, FERC clarified that procedures in its Pro Forma Tariff had been intended for generation interconnection service as well[16].

---

[16] FERC, Standardization of Generator Interconnection Agreement & Procedures NOPR, April 2002, pg. 4

2.5.3 FERC's New Directions

After several years of experience with the Pro Forma Tariff, FERC and third-party customers who are not affiliated with integrated utilities came to the conclusion that transmission services were not provided fairly to all participants under the current structure. In FERC's opinion, functional separation is insufficient to guarantee non-discriminatory transmission services. According to FERC:

> Unduly discriminatory transmission practices have continued to occur and inconsistent design and administration of short-term energy markets has resulted in pricing inefficiencies that can cause rates to be unjust and unreasonable.[17]

It has since issued a series of orders and Notices of Proposed Rulemaking (NOPR). Significant ones include Order 2000, Standard Market Design NOPR, and Order 2003. Order 2000 directs all jurisdictional utilities and encourages non-jurisdictional ones including Canadian entities to form Regional Transmission Organizations (RTO) that must be controlled and operated by independent entities[18]. FERC has expressed its desire to limit the number of RTOs in North America to just four; all utilities should belong to one of those four RTOs. BCTC has been participating in discussions surrounding the formation of the Grid West RTO with other utilities in the Pacific Northwest. It is envisioned that BCTC will co-ordinate with Grid West and continue to have full control of the BC Transmission System. Due to difficulties in forming a large RTO, Order 2000 has not been fully implemented, particularly in the West, despite significant effort and resources directed at this initiative.

[17] FERC, Standard Market Design Notice of Rulemaking, July 2002, pg. 2
[18] FERC, Order 2000: Regional Transmission Organization, December 2000

Standard Market Design (SMD) is intended to correct deficiencies in Order 888 Pro Forma Tariff. It provides standardized rules and business practices to be implemented by RTOs. The goal of the SMD is to create seamless wholesale power markets that allow sellers to market their energy easily across transmission grid boundaries, and customers to receive the benefits of a lower-cost, reliable electricity supply.

Order 2003[19], Large Generator Interconnection Agreements & Procedures, defines interconnection services along with terms and conditions for such services. It defines procedures and timelines that generators must follow for making service requests, and that service providers must adhere to for accommodating those services.

2.6 Driving Forces Behind the Changes In BC

2.6.1 Reciprocity Requirement

BC Hydro's generation resources are mostly hydroelectric. The amount of electricity generated is closely regulated by the control of the amount of water released over the hydro dams. This can be altered within a matter of minutes. This operating flexibility allows BC Hydro to store electric energy by replacing its generation output with purchased energy when the market price is low, and to increase its generation output for export when the market price is high. Powerex, active in trading electric energy and gas in many U.S. markets, carries out these transactions on behalf of BC Hydro.

---

[19] FERC, Large Generator Interconnection Agreements & Procedures, July 2003

As discussed earlier, FERC does not have jurisdiction over a Canadian entity such as BC Hydro. However, in order for BC Hydro, or its agent, to continue making direct energy trades in the U.S. market post Order 888, BC Hydro is required to obtain a Power Marketing Authorization from FERC. For FERC to issue such authorization, BC Hydro must operate a tariff similar to the Pro Forma Tariff as stipulated by the "Reciprocity" requirement under Order 888.

In November1995, BC Hydro, in anticipation of FERC's Order 888, introduced its own version of WTS. This tariff was implemented in January 1996 on an interim basis pending BCUC final approval. In its decision, BCUC directed BC Hydro to treat its transmission requirement for serving its own load in the same manner as a third-party wholesale transmission service (the 1996 Directive). Specifically, BCUC stated:

> Based on the evidence and argument before it, the Commission directs B.C. Hydro to apply all the Terms and Conditions of the Network and Point to Point Services to itself except where to do so is patently unreasonable. In those cases, where B.C. Hydro feels the application is unreasonable, B.C. Hydro is directed to apply to the Commission for relief from the provisions. The Application should state specifically which conditions should not apply and why they should not apply. [20]

In addition, BC Hydro filed its WTS to FERC for comments with respect to meeting the "Reciprocity" requirement. Unfortunately, FERC rejected BC Hydro's filing on the grounds that it was unable to afford the time to apply its test for "superiority of other forms of transmission services tariff". To date, other than independent system

[20] BCUC, British Columbia Hydro and Power Authority Wholesale Transmission Services Application Decision, June 1996, pg. 48

operators such as PJM Interconnection, no integrated utility has met the "superiority" test.

To ensure a successful Power Marketing Authorization Application, BC Hydro adopted the Pro Forma Tariff for its WTS and began offering identical transmission services in June 1997 pending BCUC approval. Approval was issued April 23, 1998. The Transmission Strategic Business Unit (TSBU) was set up as the TSP, and functionally separated from BC Hydro's other business units. The TSBU was to adhere to FERC Standards of Conduct. It was to provide equal opportunities to all customers including BC Hydro and Powerex in accordance with the Directive.

2.6.2 BC Energy Plan

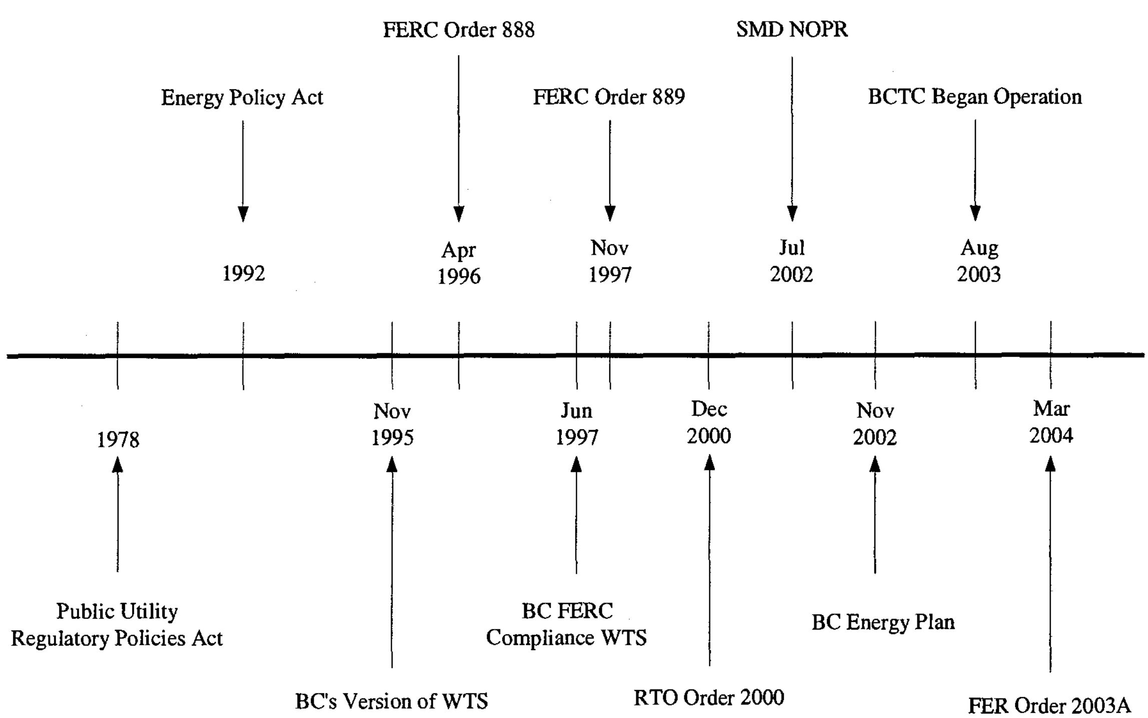
To ensure successful implementation, the Energy Plan sets out certain policy actions including the designing of a new rate structure for serving large users. This policy action requires BC Hydro to design and propose new energy stepped rates. Rates proposed will include at least two energy charges, the first for a basic consumption level and the second for consumption above the basic level, as opposed to the current single energy rate for all consumption. In addition, the second energy rate will be based on market prices such as the Mid Columbia Prices or the long run incremental cost of generation. This new rate structure will provide market signals to encourage large customers to implement energy conservation measures, develop their own generation facilities or seek alternative suppliers. The intention of this new rate structure is to provide the correct pricing signals to encourage customers to undertake efficient Demand

Side Management or self-generation initiatives, and to allow for retail access. The new rate will also provide new opportunities for IPPs.

To compete on a level playing field, IPPs will need non-discriminatory access to the transmission system. An independent TSP is essential and required for facilitating this competition. This has led to the formation of a stand-alone transmission service industry within BC.

The following Figure 2-1 shows the timeline of the various regulatory changes over the years.

Figure 2-1: Timeline of the Various Regulatory Changes



3 GENERIC TRANSMISSION ACCESS ISSUES

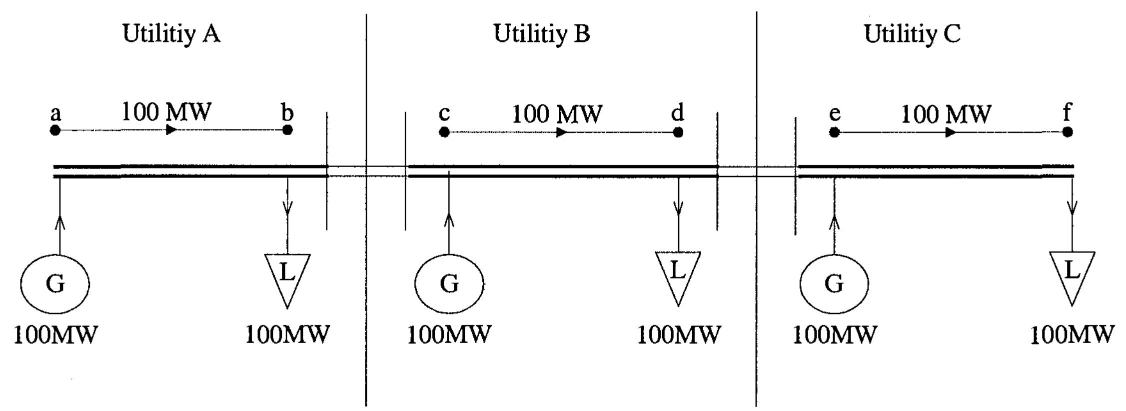
Transmission access by third parties is normally provided to facilitate sales for resale in the wholesale energy markets. The buyers of the energy are the utilities who make the purchases to supplement their energy portfolios for serving their retail customers. However, transmission access for retail competition is not common in North America. Retail access is not under FERC's jurisdiction; it is under state regulations. Some states, the Province of Alberta, and part of the Province of British Columbia have allowed large electric energy users to have access to the energy markets for some time. Retail access by large users is now being implemented for the rest of the Province of British Columbia.

The common issues facing the Wholesale Transmission Service Industry are: the degradation of the transmission system over the years due to the increase in usage combined with the lack of system enhancement; pricing policies for promoting efficient usage; and non-discriminatory transmission access. In the following sections, each of these issues will be discussed in order to provide a reference for evaluating the existing policies and practices adopted here in BC.

3.1 Transmission Planning and Enhancement

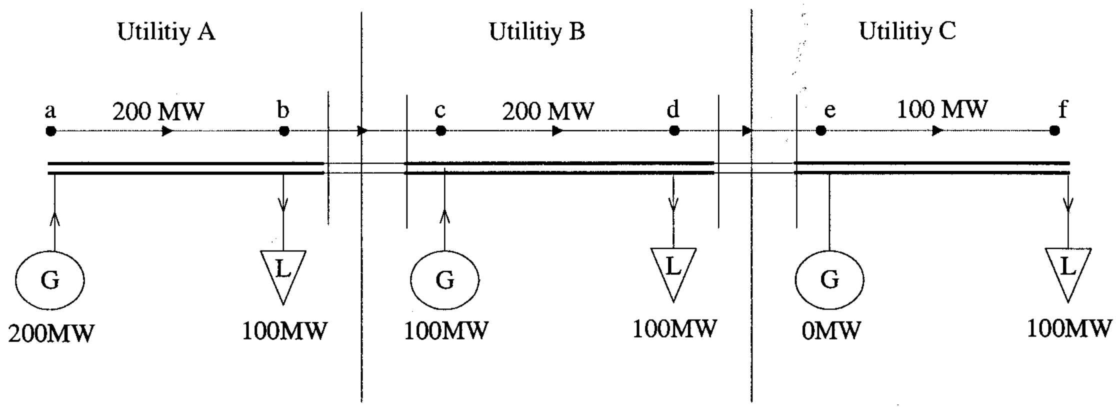
Most utilities' transmission systems in North America at one time had in excess of 120% of required capacity for serving their Native Loads.[21] However, load growth and the increase in usage for accommodating wholesale energy transactions have resulted in transmission congestion everywhere. Nowadays, it is easier and quicker to schedule transactions for wheeling over several transmission systems to serve loads thousands of kilometres away. Each one of these transactions consumes several times more capacity than one that is wheeled to serve load within an electric system. Figure 3-1 and Figure 3-2 show the difference in transmission requirements for these two types of transactions.

Figure 3-1: Energy Transactions for Serving Loads within Electric Systems



[21] Native Load: existing and reasonably-forecasted customer load for which a Transmission Provider, by statute, franchise, contract or federal, state or provincial policy or regulation, has the obligation to plan, construct or operate its system to provide reliable service.

Figure 3-2: Energy Transaction for Serving Load in a Remote Electric System



In Figure 3-1, Utility A, B and C are self-sufficient and serving their loads with their own generators' output. Each utility needs 100MW of transmission capability for transferring the power from its generator to its load. In Figure 3-2, Utility C purchases 100MW from Utility A to serve its load. Transmission demand on each of the Utility A's and Utility B's systems increases from 100MW to 200MW without any increase in total load. Wholesale wheeling services allow better access to cheaper, but distant, generation resource by utilities and, at the same time, place higher demand on transmission systems for delivering electric power across a wider geographic area to serve load. Table 3-1 shows changes in power flow due to wholesale wheeling.

Table 3-1: Power Flows (MW) without and With Wholesale Wheeling

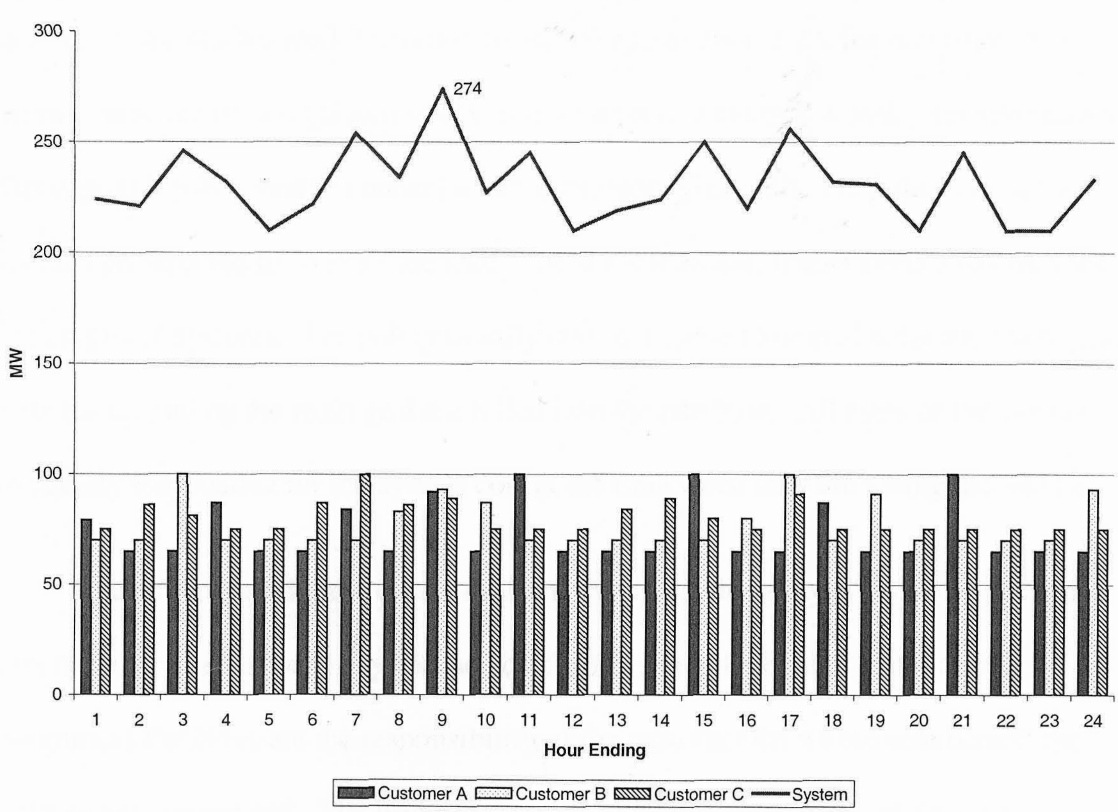
Operating Condition	a to b	b to c	c to d	d to e	e to f
Without Wheeling	100	0	100	0	100
With Wheeling	200	100	200	100	100
Change	100	100	100	100	0

Economies of scale is one of the major factors in determining the size of facilities to be added. Requiring long lead-time for planning and constructing transmission facilities have significant scale effects. To take advantage of the benefits of economies of scale, TSPs must perform ongoing analysis to ensure system adequacy and to identify problems many years in advance. Solutions are proposed and implemented before problems arise. Once new facilities are added to the system, they may be able to accommodate multiple customers as well as normal load growth. New capacity also enhances overall system reliability that benefits all customers. These proactive planning and constructing activities will ensure that services are provided in a timely manner. On the other hand, failure to provide adequate capability could degrade system reliability, and might have significant economic impacts.

Unfortunately, due to competition, utilities are reluctant to expand and enhance their respective systems since, if they do so, they will improve not only their ability to make energy sales, but also their competitors' opportunities for accessing the transmission systems, and competing in the same energy markets. Additionally, the existing pricing policies adopted for the Pro Forma Tariff have not provided the needed incentives to encourage investment to enhance and expand the transmission system. The lack of proactive planning and timely construction of new capacity have created problems for some utilities in serving their Native Loads.

Moreover, transmission system capacity is usually planned and built to serve load in aggregate, by taking load diversity into consideration. An example is a system that has three customers whose maximum consumption rate (demand) is 100MWH per hour each, but, due to different consumption patterns, each customer's maximum demand occurs at a different time. The total demand on the system at any given moment (the co-incident peak) is equal to sum of the three individual demands at that moment. It is usually less than 300MW (3 x 100MWH/H). Therefore, the transmission system needs to be built to meet only the coincident peak demand, not the simple sum of the three 100MW loads. See Figure 3-3 for illustration.

Figure 3-3: Co-incident Peak of Three 100MW Loads



In Figure 3-3, we have Customer A, B and C with maximum load of 100MW each, but they consume at this rate for only a few hours per day. For example, Customer

A's demand of 100MW occurs in the hours ending 11, 15 and 21, while that of Customer B's occurs in the hours ending 3, and 17. In the above example, the maximum load on the system is only 274MW, which occurs in the hour ending 9:00AM (i.e., between 8:00AM and 9:00AM). This illustrates that the system has to be built to meet the coincident demand of 274MW not 300MW. In this case, it is said that the system has a co-incident factor of 274/300 or approximately 91%.

3.2 Transmission Pricing Policies

Costs for transmission services consist of two components, Direct Assignment Facilities costs and Network Facilities costs. (See to Section 2.2.2 for definitions). It is common practice for a regulated utility to have a service extension policy for determining what capital it will invest to connect a new customer. Generally, the policy applies to facilities constructed to connect the load, and to some extent, it also applies to upgrades in the regional systems. The policy usually does not apply to upgrades for the main grid. Costs for upgrading the main grid are rolled into the rate base. All users of the system are equally responsible for the system cost at the time when they are taking the service.

In accordance with the cost causation principle, which says: "those who cause costs to be incurred, should pay for the costs", it is generally agreed that Direct Assignment Facilities are the responsibility of the customer for whose sole benefit the facilities are constructed. The pricing of access to transmission network facilities, however, is plagued with disagreements and litigation. It is one of the most vexing issues facing the regulators of electric utilities. Since fairness is difficult to judge, regulators tend to arrive at decisions based on their conflicting mandate. If pricing of transmission access is “incorrect”, it can distort the efficient allocation of output between the utility and its competitors. One possible result is a failure to promote competition, and a corresponding loss of social welfare. Another possible result is excessive production of energy by higher-cost ”newcomers” with a corresponding loss of market share by more efficient incumbents. In either circumstance, social welfare will not be maximized due to inefficient use of energy production plants.

The difficulties in assigning costs of common network facilities are due to the unique characteristics of the transmission network. It is a mesh system. Network upgrades to accommodate new customers will benefit all customers using the system. The transmission network is an infrastructure built to support all consumption and demand patterns in aggregate.

> Due to the dynamic and highly integrated nature of the AC grid, an upgrade in one state [area] may be required to enhance reliability and relieve congestion in an adjacent state [area].[22]

Moreover, a transmission system has significant economies of scale. Network upgrades are chosen to provide optimal efficiencies from both cost and technical perspectives. It is impractical and impossible to add just the “right” amount of capacity to service a single new customer. It is more than likely that once network upgrades are built to serve one customer, the system will have enough capacity to serve other customers as well. In economic terminology, the relevant investment is characterized by

[22] Transmission Access Policy Study Group, Effective Solutions for Getting Needed Transmission Built at Reasonable Cost, June 2004, page 6

"indivisibility". As such, many have argued that all customers, existing or new, are equally responsible for network upgrade costs.

Similar pricing issues exist in other deregulated industries. Other industries, such as the telecommunication industry and the rail industry, have experienced similar growing pains. A review of some of the literature discussing those industries, as well as the transmission service industry, can provide some insights towards pricing policies for third-party wholesale transmission access. However, in designing wholesale transmission pricing policies for one jurisdiction, we must also take its industry structure into consideration. For example, if a jurisdiction permits retail access, applying pricing policies designed for wholesale transmission access, without considering the objectives of retail competition, could have unintended impacts.

The fundamental objective of transmission pricing is to promote the economically efficient transmission and generation of electricity. Rates charged "shall ensure that, to the extent practicable, costs incurred in providing the wholesale transmission services, and properly allocable to the provision of such services, are recovered from the [party seeking mandatory wheeling] and not from a transmitting utility's existing wholesale, retail, and transmission customers."[23] These costs include utility's opportunity costs, a legitimate contribution to fixed costs, and the benefits to the transmission system of providing wheeling services. In other words, transmission pricing should not result in cross-subsidization between the utility's Native Load customers and customers seeking wholesale transmission access and vice versa.

---

[23] Baumol, William & Sidak, Gregory , Transmission Pricing and Stranded Costs in the Electric Power Industry, the American Enterprise Institute, Washington, D.C., 1995, page 139

The pricing models often promoted for setting efficient pricing policies are marginal cost pricing, average incremental cost pricing and efficient component-pricing.

3.2.1 Marginal Cost Pricing

The competitive model tells us that for promoting economic efficiency, the price of a product should be equal to the marginal cost of producing it. This is a well-known principle that characterizes competitive equilibrium. Marginal cost of a product is the cost of producing just one more unit of that product. The objective of a firm to maximize its profits will motivate the firm to expand its production as long as marginal cost is less than the price of that product. At the point of competitive equilibrium, where marginal cost is equal to the price, the firm stops producing any additional units since no further profits can be realized.

The marginal cost pricing principle works best in perfectly competitive markets. Products or services offered are perfectly competitive if there are no barriers to entry and if there are many suppliers. Firms are competing to sell products or services at prices set outside the firms. Firms that are highly efficient will be able to produce at marginal costs lower than the prices. In the long run, efficient firms will make sufficient profits to pay for their fixed costs. However, the marginal cost pricing principle is a recipe for bankruptcy in industries that have significant economies of scale, since pricing at marginal cost will not allow the firm to recover its fixed costs. In the transmission service industry, price discounts are usually offered to short-term, “as available” transmission services. The intent of the discounts is to reduce transaction costs of low margin energy deals. Transmission marginal cost pricing can be used to set floor prices for these "opportunity" transmission services, which will improve the utilization of the transmission system and make additional contributions to cover fixed costs.

3.2.2 Average Incremental Cost Pricing

The average incremental cost of the entire service is defined as the difference in the firm's total costs with and without the specific product supplied divided by the output of that product. For a firm offering only one product, the average incremental cost is the firm's total cost, including input fixed costs, divided by the total output of that product. Note that if firm uses assets purchased in the past for the production of a product, the fixed costs of those assets must be evaluated at the most economical replacement costs. This is done to reflect the principle of economic efficiency. In a competitive market, owners would want to maximize the benefits they can get from the assets. They can do so by continuing to produce the same product, re-deploying or selling the assets. If the demand for the product is strong, the owner will certainly not sell the assets for less than the replacement costs, which new entrants must incur to enter the market.

In the context of transmission services, since all transmission services facilitate the injection of electrical power into, and the withdrawal of the same from the main grid, one conclusion that can be drawn is that transmission services are a single product, regardless of whether they are labelled as Native Load, NITS or PTP. Therefore, average incremental cost is equal to the utility's total transmission costs, including replacement costs of existing facilities and new network upgrade costs, if any, divided by the total capacity sold. One concern is that network enhancements may have been accelerated to serve wheeling customers, and Native Load customers will have to pay for system benefits before the benefits are needed. One might argue that a benefit paid for before it is needed is tantamount to a cost subsidy by Native Load customers. Another conclusion is that wholesale transmission service is an additional product offered by a utility over and above the traditional transmission service it provides to its Native Load. Then the average incremental cost for providing wholesale transmission service is as follows:

$$AIC_{WTS} = [TC(TSNL, WTS) - TC(TSNL, 0)]/wts.$$

Where:

AIC_{WTS} = wholesale transmission service average incremental cost

TC(TSNL, WTS) = total cost for providing transmission service to Native Load and wholesale transmission service

TC(TSNL,0) = total cost for providing transmission service to Native Load alone

wts = wholesale transmission service quantity

However, all network facilities, which are common and will be used to provide both services, are neither incremental to service Native Load, nor to service wheeling customers. If the utility were to discontinue either service, these facilities would still be needed. The wheeling customers may argue that the utility started to provide service to the Native Load first, so the costs of facilities built prior to the introduction of wheeling services should be the responsibility of the Native Load customers. But, if we accept the argument that the timing of the introduction of services "is an irrelevant piece of history"[24], then the average incremental cost for both Native Load transmission service and wholesale transmission services is the same.

It is interesting to note that embedded costs are the historical counterpart of average incremental cost. Embedded cost is simply the incremental investment that was incurred in the past. If the old assets are properly evaluated by adjusting for inflation and depreciation, embedded cost is equivalent to replacement cost and becomes equal to incremental cost.

Average incremental cost pricing can be an effective pricing principle to encourage customers to choose locations where cost of service is low. This pricing methodology is especially effective for the BC Transmission System, which has most of its loads located in the Lower Mainland (LM), and most of its generators located in the North Interior (NI) and South Interior (SI). To illustrate how average incremental cost can be applied to set locational pricing for transmission services in BC, let's assume total load in the LM is xMW, in NI is yMW, and in SI is zMW. The average incremental cost of each respective region is as follows:

$AIC_{LM} = [TC(LM, NI, SI) – TC(0, NT, SI)]/x;$

$AIC_{NI} = [TC(LM, NI, SI) – TC(LM, 0, SI)]/y;$ and

$AIC_{SI} = [TC(LM, NI, SI) – TC(LM, NT, 0)]/z.$

[24] Baumol, William & Sidak, Gregory , Transmission Pricing and Stranded Costs in the Electric Power Industry, the American Enterprise Institute, Washington, D.C., 1995, page 74

Since historical costs of depreciated transmission assets are replaced by their most economical replacement costs in calculating the average incremental cost, the total incremental cost will likely exceed the utility's embedded cost, which is the base for determining the utility's revenue requirement. Therefore revenue collected based on average incremental cost pricing as above will exceed the embedded-cost-based revenue allowed to be collected under a rate base regulation environment. Adjustments must be made. Each AIC will need to be adjusted down by a factor of [revenue requirement]/[total revenue], for example. Table 3-2 shows samples of locational pricing calculations.

Table 3-2: Sample Application of AIC on Locational Pricing ($000)

Region	Revenue Requirement	Quantity	AIC[25]	AIC Revenue	Adjusted AIC	Adjusted AIC Revenue
LM		4,500	75	337,500	70	313,567
NI		1,310	50	65,500	46	60,855
SI		1,190	55	65,450	51	60,809
VI		2,015	80	161,200	74	149,769
Total	585,000			629,650		585,000

3.2.3 Efficient Component-pricing

Efficient component-pricing requires that the price should be equal to the incremental cost of transmission service plus any opportunity costs that the utility has to incur for providing transmission services to its competitors. The opportunity cost includes the loss of profit from energy sales that the utility would make in the absence of mandatory wholesale transmission services. This formula is intended to ensure that

[25] Fictitious numbers

Native Load customers will not be negatively impacted. It is based on the assumption that profits made by the utility from energy sales are used to reduce rates charged to its retail and wholesale customers. When a utility provides mandatory wholesale transmission services to its competitors, it loses the opportunity to make similar energy deals, resulting in a loss of benefit by its retail and wholesale customers. This loss is considered an incremental cost that must be recovered from wholesale transmission services. However, the loss opportunity assumption is valid only for short-term transmission services and only when there is insufficient capacity to accommodate both the utility's and its competitor's energy transactions. It is not valid for long-term transmission services since transmission capacity can be built to provide services to both the utility and the competitor.

If a utility's opportunity costs were ignored, social welfare could be reduced. For example, if the energy price for a sale is $30/MWH, and the utility's average incremental costs for energy production and transmission service are $5/MWH and $2/MW/H respectively, then the economic benefit resulting from this deal is $23/MWH ($30 - $5 - $2). The efficient component-pricing rule tells us that the price for transmission service should be set at $25/MW/H ($23 + $2). If the available transmission is sold to the competitor at the average incremental cost of $2/MW/H, this competitor, in theory, could make the sale, even if its energy production cost is an iota lower than $28/MWH, and it would still make a small profit. This is so because the competitor would enjoy a net surplus equal to the difference between $30 and its own production cost plus the $2 access charge. But, the net economic loss would be approximately $23/MWH, i.e. the difference between the competitor's production cost ($28) and the utility's production cost ($5). On the other hand, if the transmission price were set at $25/MW/H, this competitor would not make the sale, since doing so would result in its loss of $23/MWH. Clearly, an efficient component-pricing rule would prevent inefficient use of resources.

However, the utility's opportunity costs are not transparent and, therefore, difficult to determine, even in the short-run. Pricing long-term wholesale transmission services based on the loss of opportunity is an impossible task. Nonetheless, an alternative transparent method for determining a utility's opportunity costs could be used. One well-known mechanism is the auction process. The utility sets the floor price based on its incremental transmission cost, and the participants make their bids for the services based on their costs and opportunities. In the above example, the utility is able to bid for the transmission service at a price as high as $25/MW/H, while the competitor can bid no more than $2/MW/H. Thus, the utility will be able to make the sale at the lower energy production cost of $5/MWH as opposed to $28/MWH if the competitor makes the same sale. The economic benefit of $23 is therefore captured. Inefficient use of resources is therefore prevented.

Therefore,

> If transmission facilities are to continue to be owned by the utilities and used to provide transmission service both to themselves and to their competitors,....[e]conomic efficiency requires that this service be priced in accordance with what has been called the efficient component-pricing.[26]

[26] Baumol, William & Sidak, Gregory , Transmission Pricing and Stranded Costs in the Electric Power Industry, the American Enterprise Institute, Washington, D.C., 1995, page 5

The efficient component-pricing rule also requires that the utility charge itself the same prices it charges others for using the same transmission services. This requirement has been enunciated by many. This requirement is also evident in the BCUC's 1996 Directive discussed in Section 2.6.1.

On the other hand, some wholesale transmission customers have asserted that allowing utilities to charge their competitors the same prices the utilities charge themselves for the use of the same transmission services does not necessarily prevent an inefficient use of resources. To illustrate, assume that the energy price is $30/MWH, the utility's marginal energy production cost is $10/MWH and that of its competitor is $9/MWH. The efficient component-pricing says the utility should set the transmission wheeling price at $20/MW/H. In this example, it does not matter whether the utility completes the energy transaction or sells transmission service. It will make $20/MWH in profit in either case. The competitor would be willing to pay up to a fraction below $21/MW/H for the wheeling service. However, if the utility sets the transmission price at $21/MW/H or higher for certain strategic reasons, the competitor will not make the energy sale. In this case, the utility will complete the energy sale, pay the higher transmission charge to itself and still make $20/MWH. Table 3-3 summarizes the utility's revenues, costs, and profits for both scenarios discussed.

Hence, charging themselves is equivalent to moving money from their right pocket to their left pocket. Unless properly scrutinized, the utilities could strategically price their competitors out of the energy market.

Table 3-3: Utility's Profits for selling either Energy or Transmission Service

	Transmission Charge Set @ $20/MW/H		Transmission Charge Set @ $21/MW/H or Higher	
Energy Sale by	Utility	Competitor	Utility	Competitor
Energy				
Revenue	30	0	30	N/A
Production Cost	(10)	0	(10)	N/A
Transmission				
Revenue	20	20	21	N/A
Cost	(20)	0	(21)	N/A
Profit	20	20	20	N/A

3.3 Non-discriminatory Transmission Access

Access has two significant and pertinent attributes: it is an intermediate good; and it is the same good that the utility produces for itself and others as an input to the final product sold in competitive power markets. Therefore, if utilities have control over access to the transmission system, non-discriminatory access to third parties may not be achievable. This could be the result of the following two factors. First, the utilities have far better information about the transmission system and can use this information to set aside low cost capacity for their own use, leaving the responsibility for costly network upgrades to their competitors. Second, as network upgrades provide many benefits to all users, it is difficult to assign the cost responsibility among customers. The utilities' predilection is to allocate higher costs to their competitors.

Discriminatory transmission access can exist in two situations: (1) a lack of independence of the TSP; (2) explicit transmission rights granted to the users based on when they first become the customers, thereby providing them with a cost advantage over other users. The former is being resolved in many jurisdictions, including British

Columbia, either voluntarily or in compliance with FERC' Order 2000 (discussed in Section 2.5.3) by creating independent system operators. For the latter, it is evident that attempts have been made by a few regulators and independent system operators to create a level playing field for all customers. They have particularly stressed the point that no customer can claim a right to transmission network capacity based on historical usage. Some jurisdictions have codified this principle in their public policies that "[t]here are no explicit transmission rights"[27] granted to either generators or loads.

[27] Alberta Energy, Transmission Development Policy, page 9, November 2003

4 WHOLESALE TRANSMISSION SERVICES

To meet FERC's Reciprocity requirement, BC Hydro adopted the FERC Pro Forma Tariff in June 1997. The Pro Forma Tariff, or the WTS as it is referred to in BC, was designed for investor-owned integrated utilities in the U.S. It was designed based on the premise that it would be managed as an adjunct to the standard integrated utility's tariff. That is, the integrated utility would continue to engage in all electricity industry functions as described in Section 2.3 including planning, constructing, and operating its transmission system to serve its Native Load. As the name implies, the WTS is intended to promote the competition in the wholesale energy markets. Wholesale transmission services are provided in addition to the host utility's traditional transmission obligation. These services are provided to third-party customers as well as to the utility's marketing business unit for making off-system sales[28] at similar quality and priority to transmission services provided to the Native Load. Moreover, WTS is intended for wheeling electric energy over the TSP's system to serve markets outside the host utility's retail service area. It is not intended for facilitating retail competition within an integrated utility's service territory. Nonetheless, some jurisdictions have made retail transmission access available to large retail users under the same terms and conditions of the WTS. However, if the objective of retail access is to promote competition in serving Native Load,

[28] Off-system sales are those energy transactions the utility makes to other utilities or marketers in a competitive energy market

applying WTS to retail transmission access without changes to traditional retail pricing rules could lead to failure in meeting the stated objective.

This chapter evaluates current WTS' planning, accessing and pricing rules against those discussed in the preceding chapter. Past experience will be used as examples in order to illustrate the challenges facing the BC transmission industry.

4.1 WTS Transmission Planning Issues

As defined under the WTS, a TSP is a business unit within an integrated utility that has other business interests as well. These interests include generation, distribution, and retail service. Usually, the TSP is also affiliated with an energy marketer competing in the wholesale electric energy markets. The TSP is expected to continue to have the responsibility for long-term system planning activities. These activities include identifying future network upgrades that are required to serve an integrated utility's Native Load and load growth as part of the TSP's statutory, franchise, or contractual obligations. As such, the TSP has ongoing access to the utility's resource planning and Native Load forecast information to carry out its planning activities. Annually, the TSP is expected to produce a ten-year transmission plan that identifies network upgrades for serving Native Load. This transmission plan will form the basis for processing and accommodating wholesale transmission services such as NITS and PTP. Additional system re-enforcement or advancement of network upgrades, which have been identified in the plan, may be required to accommodate a WTS service request.

If a TSP takes the view that it is independent, and that it does not have Native Load, it does not have the responsibility for ensuring long-term transmission adequacy by identifying and constructing network upgrades to meet load growth. The TSP will only perform planning studies to identify specific network upgrades required to accommodate service requests. Furthermore, it will construct new facilities only if customers commit to service contracts. In this case, network upgrades will be piecemeal. They may be implemented as interim solutions until a service request triggers a major system upgrade that may render previous piecemeal re-enforcement redundant. This approach to planning and constructing new transmission facilities is reactive and not consistent with the approaches that are required where economies of scale exist. As discussed in Section 3.1, transmission systems have large economies of scale and transmission facilities have long lead-times. Therefore, system enhancements must be implemented in advance of load growth. Proactive planning and construction of network upgrades for future needs are necessary in order to take advantage of economies of scale and ensure system adequacy. Therefore, a reactive approach to planning and construction of network upgrades is undesirable for transmission systems. This approach may lead to degradation of system security and reliability, not to mention inadequate capacity to service Native Load. To illustrate the issues with this reactive planning process, we can analyse the problems the former BC TSP experienced in the past few years.

As mentioned earlier, BC Hydro assigned the responsibility for providing non-discriminatory transmission services to its TSBU. The TSBU treated BC Hydro's transmission requirements for serving its Native Load in the same manner as it would a third-party customer's needs. This was done to be in compliance with the BCUC 1996 Directive (Section 2.6.1). BC Hydro must apply for transmission service required for its Native Load like any other customer. Essentially, the TSBU assumed a similar business model to that of an independent TSP. The TSBU suspended its traditional long-term planning function that would identify and co-ordinate the construction of the network upgrades required to serve an integrated utility's load growth. Instead, the TSBU relied on generation and retail business units to identify services that BC Hydro's Native Load customers would need. Network upgrades would be constructed only if those business units committed to a long-term service contract. It is expected, under FERC's WTS, that the decision for procuring transmission services for making off-system sales is the responsibility of the utility's generation or marketing business unit. When applications for those services are made, the utility's transmission business unit is expected to treat them in the same manner as it would treat those of third parties. It is not expected, however, that the utility will apply to and contract with its own transmission business unit for transmission service to meet the need of its Native Load. The approach taken by BC Hydro resulted in transferring the decision of BC Hydro's transmission requirements for its Native Load to its generation business unit which did not have the same level of transmission expertise required for taking on such responsibility. As a result, no commitment was made and no major transmission facility was built for years.

In addition, the first-come, first-served rule required TSBU to process and perform system studies for one transmission request at a time. Since the status and outcome of one request would have significant impacts on others in the queue, a service request next in the queue could not be processed until the preceding one was finalized. This approach caused major delays for customers. For example, there were a few transmission requests submitted in late 2000 for service commencing January 2001. System studies for determining network upgrades needed to accommodate these service requests were not completed until June 2002. The studies concluded that the construction of those network upgrades would not be completed until December 2004 for service commencing January 2005. The lengthy delay denied customers timely access to the system and resulted in opportunities lost to all parties involved.

Secondly, the fundamental planning criteria are also altered. The change in practices, though subtle, may have significant impacts on the results. As discussed in Section 3.1, transmission system capacity is usually planned and built to serve load in aggregate, by taking load diversity into consideration. The system is planned and built to serve the coincident peak load, not the numerical sum of all individual loads. For example, if a system has ten individual loads of 100MW each, the simple sum of these loads is 1,000MW. Since loads vary from minute to minute, the coincident peak is usually less than 1,000MW. Assume that the coincident factor is 80%. Then the coincident system peak of this fictitious system is 800MW (1000MW x 0.8). This figure will be used for planning and other purposes if all the loads are served as Native Load or under NITS.

Assume further that one of the ten 100MW loads is planning to switch to PTP service. Upon receiving a request for such service, the TSP performs a planning study, known as the System Impact Study (SIS), to determine whether network enhancement is required to accommodate such request. Table 4-1 shows assumptions that will be made for this SIS.

Table 4-1: Assumptions for the System Impact Study

Transmission service	Load (MW)	Note
Native Load/NITS (remaining)	720	= 9 x 100 x 80%
Point-to-Point	100	
Total System Peak Load	820	

In Table 4-1, due to a change in service designation of the 100MW from being served under Native Load to PTP, nine 100MW loads remain part of Native Load. Since the co-incident factor is still 80%, the co-incident peak of the Native Load is therefore 720MW. On the other hand, PTP service is assumed to be constant at 100MW for all hours. Hence, the total system load is now assumed to be 820MW. This fictitious transmission system now must be planned and built to service 820MW, a 20MW increase, although it continues to serve the same ten 100MW loads with the same consumption patterns. Some benefits of load diversity are deemed lost. This example illustrates a case of inefficient planning assumptions adopted due to WTS rules and business practices.

Finally, the locations of the generating plants and their availability also play significant roles in the determination of transmission requirements for the entire system. That is to say, if a generating plant located near a load centre is available for serving loads during peak periods, it can reduce transmission requirements. This approach is generally known as the re-dispatch option, which is used for managing transmission congestion and for avoiding building more expensive transmission facilities. If the re-dispatch option is not considered by, or it is withheld from, the TSP, more transmission facilities may have to be constructed, and all consumers are worse off as a result.

Figure 4-1 shows an electric system with 2,000MW of generation (G1) at one end of the system, and 2,000MW of load at the other end. The load reaches 2,000MW only for a short time each year as shown in Figure 4-2. With this system, the transmission system capability must be at least 2,000MW. On the other hand, if 200MW of generation (G2) at the load end is available for dispatch during peak period, the transmission requirement is reduced by 10%. (See Figure 4-3 and Figure 4-4.) Using G2 at the load end to serve load for a short period is sometime more economical than building network upgrades, even if the production cost of G2 is higher than that of G1. Generation at the load end is used for illustrating purposes. It is equally effective if imports from another system are used.

Figure 4-1: System Configuration 1

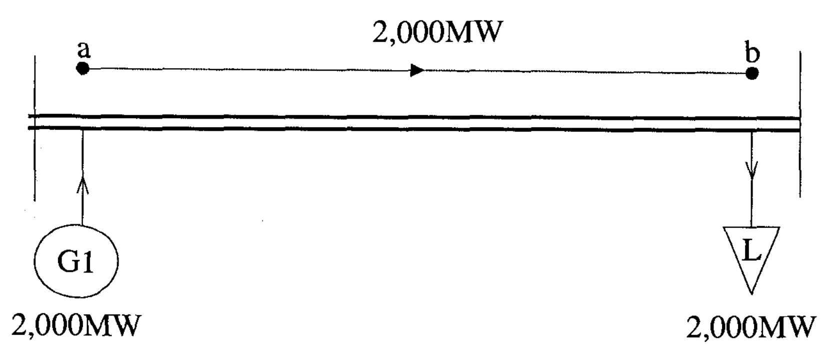


Figure 4-2: Transmission Capacity without Re-dispatch Option

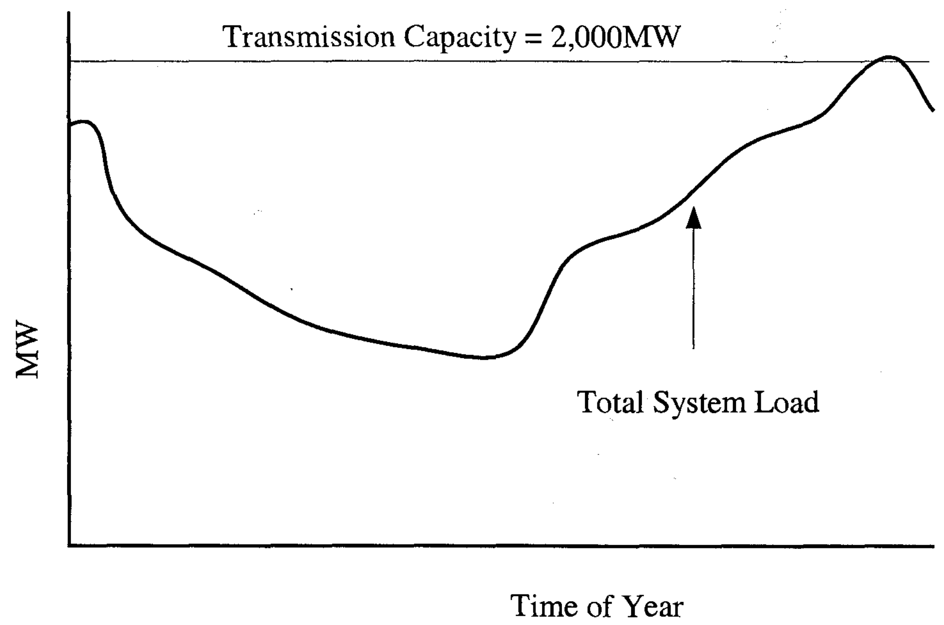


Figure 4-3: System Configuration 2

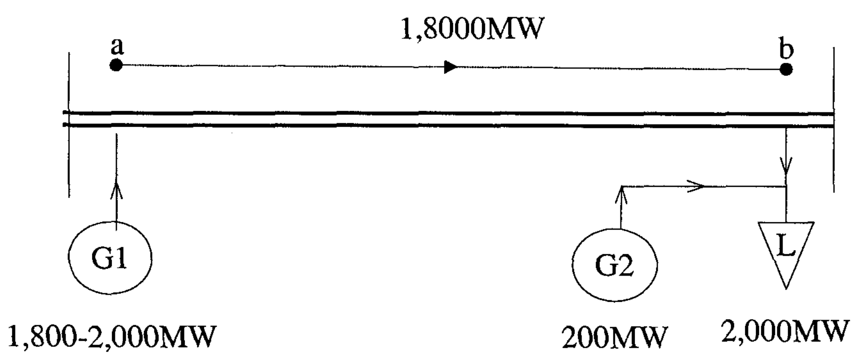
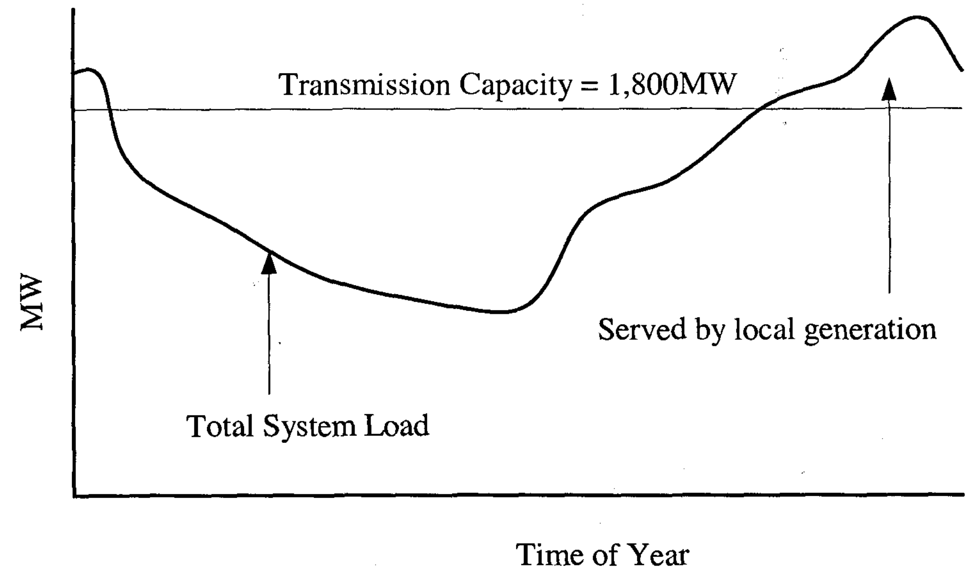


Figure 4-4: Transmission Capacity with Re-dispatch Option



4.2 WTS Pricing Policy

Under WTS, PTP service is priced at average embedded cost. The monthly charge is based on contract capacity. Native Load and NITS customers are responsible for the balance of the total cost allocated to the transmission services; their monthly charges are calculated based on their actual load ratio shares, which vary from month to month. For example, a transmission system with total cost of $600M a year (or $50M a month), and a peak demand of 10,000MW, has an average embedded cost of $5,000/MW/month (600M / 10,000 / 12). Therefore, the customer is charged 5,000/MW/month for PTP service. Assume that there are 1,000MW contracted for PTP service, which represents 10% of the system peak. Then the monthly PTP revenue will be $5M and the remaining $45M cost will be recovered from Native Load and NITS customers. To determine the charges for Native Load and NITS, assume that Native

Load, NITS, and PTP customers' peak loads for the month are 60%, 30%, and 10% of the system peak respectively. Then: (See Table 4-2 for summary)

Native Load Monthly Charge = \$50M x 60% = \$30M; and

NITS Monthly Charge = \$50M x 30% = \$15M.

Table 4-2: Summary of Monthly Revenues from Various Services

Service	Load		Revenue
	MW	%	
Native Load	6,000	60%	\$30M
NITS	3,000	30%	\$15M
PTP	1,000	10%	\$5M
Total	10,000	100%	\$50M

For new long-term services that require network upgrades, prices charged are the higher of average embedded cost and incremental cost ("the higher of rule"). Incremental cost includes costs of building, operating and maintaining the network upgrades. When transmission upgrades are required, a revenue test is applied to determine whether or not the new customer has to pay an up-front contribution in addition to the basic monthly charge based on average embedded cost. The financial contribution by the customer is determined as follows:

The higher of zero, or

(1) NPV of network upgrade costs + (2) NPV of X annual operating and maintenance costs – (3) NPV of X annual revenues

Where X is the lesser of the contract term and ten years.

The amount rolled into the rate base is equal to the lesser of [(1) + (2)] and (3).

For short-term services, which are provided using idle capacity, prices are based on embedded cost. Discounts are available for export service or services for wheeling between Alberta and the U.S. The discounts are intended to encourage marginal energy deals to proceed and, thus, improve system utilization.

4.2.1 The Applications of the WTS Pricing Policy

The application of the higher of rule on long-term PTP service is straightforward. The annual incremental revenue is simply equal to the contract capacity multiplied by unit price. Therefore, the customer's up-front contribution and the roll-in network upgrade costs can be determined readily.

Applying the revenue test to determine the up-front contribution from Native Load and NITS customers and the rolled-in network upgrade costs for new service is not as straightforward, however. It is not applied for the following reasons. Network upgrades for NITS may be required in situations where a generator is connected to the grid, and where a new load is integrated into the system. The interconnection of a generator and a load usually occur at different points in time. If the existing NITS customer builds a new generator for serving its future load growth, some network upgrades are usually required. But, as its total load does not change, there is no resulting increase in its load ratio share. Since load ratio share is the basis for assessing the NITS charge, the incremental revenue from this customer will not change either. Using the example discussed above, revenues from each of the customers will remain the same. If the revenue test is applied to determine the customer contribution, the customer will have to pay for all network upgrade costs up front, and there will be no rolled-in cost.

On the other hand, when a customer's new load is added to the system, its load ratio share increases. But, due to load diversity and other customers' consumption patterns, the increases in the "actual" monthly load ratio share cannot be predicted with much accuracy. Network upgrades can also be driven by Native Load and NITS customers' annual ten-year load and generation forecasts. Similarly, determining incremental revenues from these forecasts is an impossible task. Therefore, the revenue test for determining customer contribution cannot be used.

For the above reasons, the "higher of rule" is in practice applied only to PTP service. Network upgrade costs for integrating Native Load and NITS's new load and new generation are rolled into the rate base automatically. All customers will eventually pay a proportional share through a higher average rate. To illustrate, assume that the incremental investment required for serving a new 100MW NITS load is $100M, and the resulting incremental cost is approximately $10M[29] per year, based on a 10% discount rate. Therefore, the total annual cost of the transmission system, discussed at the beginning of Section 4.2, is now $610M ($600M + $10M), and the average rate is:

$610M / (10,000+100)MW / 12 = $5,033/MW/month

[29] Annual cost is approximately 10% of investment at 10% discount rate

Table 4-3 summarizes the overall impacts on each of the customers. It shows that the Native Load customer and PTP customer both share some of the costs of serving this NITS's new load.

Table 4-3: Impacts on Monthly Revenues from Various Services after the Rolled-in Costs

Service	Before Rolled-in Costs			After Rolled-in Costs		
	MW	%	Revenue	MW	%	Revenue
Native Load	6,000	60%	$30M	6,000	59.4%	$30.2M
NITS	3,000	30%	$15M	3,100	30.7%	$15.6M
PTP	1,000	10%	$5M	1,000	9.9%	$5.03M
Total	10,000	100%	$50M	10,100	100%	$50.83M

But, if the new 100MW load is served under long-term PTP, assuming the contract term exceeds ten years, the incremental annual revenue, rolled-in cost, and customer contribution are as follow:

Incremental Revenue = 100MW x $5,000/MW/month x 12 = $6.0M;

NPV of Incremental Revenues = NPV(6M for 10 years at 10%) = $36.9M;

Roll-in Cost = $36.9M; and

Customer Up-Front Contribution = $100M – $36.9M = $63.1M

Therefore, the total annual transmission cost and the average rate are:

Total Annual Cost = $600M + 10% of $36.9M = $604M

Average Rate = $604M / 10,100MW / 12 = 4,983/MW/month

The impacts on monthly revenues from each of the customers are summarized in Table 4-4.

Table 4-4: Summary of Monthly Revenues from Various Services after Adding 100M PTP

Service	Load		Revenue
	MW	%	
Native Load	6,000	59.4%	$29.9M
NITS	3,000	29.7%	$14.9M
PTP	1,100	10.9%	$5.5M
Total	10,100	100%	$50.3M

As shown in Table 4-4, all customers see a small reduction in monthly transmission cost per MW, but the PTP customer has to make a large up-front financial contribution of $63.1M

WTS pricing methodology disadvantages PTP customers in three ways. First, the "higher of rule" is not applied consistently to all customers. While PTP customers must make an up-front capital contribution if the incremental revenue from a new PTP service is insufficient to pay for the costs of all Network upgrades, which benefit all customers, Native Load and NITS customers are exempted from such burden. Second, in calculating the PTP customer's up-front contribution, only ten years of incremental revenue from the new PTP service are used to determine the up-front contribution, even if the customer has a longer contract term. And third, the PTP customer must pay a financial contribution if the incremental cost of serving its new PTP load is higher than the average embedded cost, but it does not receive any credit if the incremental cost is less than the average embedded cost. Clearly, this pricing policy is inconsistent, and it has resulted in different roll-in treatment for different service.

4.2.2 The Efficiency of the WTS Pricing Policy

The WTS Tariff originally was implemented in BC in order to meet FERC's Reciprocity requirement. The tariff is intended to facilitate competition in the wholesale energy markets. As such, cost recovery and no subsidy from Native Load customers are the two dominating criteria for efficient pricing policy. As discussed in the previous chapter, incremental cost pricing or efficient component-pricing is best suited. This means that all costs incurred to serve a specific customer must be recovered from that customer through the provision of wholesale transmission services.

For long-term wholesale transmission services, the higher of rule discussed at the beginning of Section 4.2 applies. This rule, however, does not meet the efficiency criteria since only the incremental costs of capitalizing capital, operating, and maintaining network upgrades are included. This rule does not take into account the benefits contributed to the system by network upgrades, or the costs of lost opportunities by the utility. On the other hand, in cases where no network upgrade is required due to excess capacity built for future Native Load growth, embedded cost pricing is used, and the costs of maintaining the transmission capacity needed to serve Native Load growth is ignored. In both cases, WTS pricing policy fails to meet the objectives.

The WTS pricing policy encourages free riders. Specifically, it encourages wheeling customers to hog low cost transmission by submitting multiple transmission requests for different amounts of transmission capacity. The customers' main objective is to obtain excess capacity built for, but not currently needed by, the Native Load customers, or capacity that requires cheap network upgrades. If expensive network upgrades were required to accommodate the service, the customers would withdraw the requests; they would wait for someone, most likely the Native Load customers, to fund those expensive upgrades. Due to economies of scale, transmission capacity created by the upgrades will probable exceed what is required to meet Native Load customers' immediate needs. The free riders will again come knocking at the door.

> This mechanism is poorly adapted to a dynamic AC grid, where benefits and beneficiaries of an upgrade are many, difficult to assign, change over time and can be enjoyed by "free riders" (i.e., entities other than the funding entity). Participant funding invites a game of chicken where would-be beneficiaries may sit back in the hope that others will step forward to bear the cost of an upgrade.[30]

With the introduction of retail access to the BC Transmission System, the existing WTS pricing policy needs further review. As discussed in Chapter Two, the Province hopes to encourage generation competition for serving large electric energy users by IPPs. Since the IPPs' customer base will be small compared to that of the utility, they will not be able to compete under the existing WTS pricing policy and the current state of the BC electric industry structure for the following reasons. As mentioned in Chapter One, the transmission system has many possible congested paths, and hence an incremental wheeling service would probably trigger the need for expensive network upgrades. Under the WTS rule, the transmission customer who requires the service must pay for the costs of all those upgrades. An incumbent utility with a large customer base

[30] Transmission Access Policy Study Group, Effective Solutions for Getting Needed Transmission Built at Reasonable Cost, June 2004, page 8

will enjoy advantages, since it has the ability to spread the incremental transmission costs over all of its retail customers who are charged for their services under average embedded cost pricing. The IPP, on the other hand, will have to recover all of its costs from a much smaller customer base.

From retail customers' perspective, all are Native Load customers who will ultimately pay for all the transmission costs and, therefore, it should not make any difference whether the incumbent utility or an IPP serves their energy needs. The existing WTS pricing policy, if it is applied to retail access, will change the outcome of upstream competition. Average incremental cost pricing, however, encourages economic use of transmission and generation resources. Average incremental cost pricing does not interfere with upstream competition. IPPs and the incumbent utility will compete to provide efficient generation on a level playing field as intended by the Energy Plan.

Furthermore, the transmission system is considered the "energy highway"[31]. It has been recognized that the transmission system is a public infrastructure used for delivering the electric energy commodity to the market in a similar way as other public infrastructures, such as our highway system. If the transmission system is correctly described as an "energy highway", then charging only the new customers for using this energy highway a higher rate is analogous to levying toll charges only on the new users of our public highways in order to recover roadway expansion costs. Table 4-5 provides a further illustration of this analogy.

[31] BCTC, Board of Directors Strategy Retreat, pg. 2, April 2004

Table 4-5: WTS Pricing Methodology & Equivalent Public Highway Cost Recovery

WTS Pricing Methodology	Equivalent Public Highway Cost Recovery
Scenario 1 Transmission system has sufficient capability to serve all customers. All customers pay average rate.	Scenario 1 Public highway system has sufficient capability to allow the movement of people goods and services freely. All users of the highway system pay for their usage through taxes.
Scenario 2 Transmission system is congested. Usage increases to the point where additional capacity must be built to accommodate new customers. Since revenue collected from the new customers under the average rate is sufficient to cover system expansion cost, all customers pay the average rate.	Scenario 2 Public highway system is congested. Population and economic activities have increased to the point where additional capacity (lanes) must be built to accommodate new growths. Since tax revenues from growths are sufficient to cover system expansion costs, all users of the highway system pay for their usage through taxes.
Scenario 3 Transmission system is congested. Usage increases to the point where additional capacity must be built to accommodate new customers. Since revenue collected from the new customers under the average rate is **insufficient** to cover system expansion costs, all customers pay average rate. But, in addition to the average rate, the **new customers** must pay the difference between expansion cost and the revenue derived from these new customers under the average rate.	Scenario 3 Public highway system is congested. Population and economic activities have increased to the point where additional capacity (lanes) must be built to accommodate new growths. Since tax revenues from growth are **insufficient** to cover system expansion costs, all users of the highway system pay for their usage through taxes. But, in addition to taxes, the **new users** (new residents, new drivers or new business as of certain date) must pay toll charges.

For short-term services, discounts are offered to improve the utilization of the transmission system. Short-term service prices are set based on the differences of the short-term energy prices of two adjacent (or relevant) energy markets[32], and capped at the average embedded cost. For example, the energy price in market X is $10 and in market Y is $20. Ignoring transmission losses, the short-term transmission price is equal to ($20 - $10)/4 or $2.5. The difference between X and Y represents the value of the transmission, and it is shared equally among "4" parties, the energy buyer, seller, and two TSPs. Opportunity costs are ignored. If the efficient component-pricing is used, however, the transmission price will set at $10, assuming that the Utility Y is selling to Utility X. This formula-based pricing methodology does not meet the efficient pricing rules.

In summary, WTS pricing methodology cannot ensure subsidy-free pricing for Native Load customers and wholesale wheeling customers. It also fails to encourage efficient use of transmission and generation resources, since it would apply different treatment to the roll-in of network upgrade costs to the same Native Load customers if they choose to be served by different electric energy providers.

4.3 WTS Accessibility

Since WTS are provided on a first-come, first-served basis, available transmission capacity is awarded to those who are able to submit their applications early rather than to those who value the service the most. For example, some short-term firm services were posted monthly at midnight on the first day of the month. Wheeling customers used to

[32] For BC, a proxy of Alberta Pool Price and the California-Oregon-Border Price are used.

wait until the clock struck midnight to submit their applications through the OASIS, and to find out that they had lost their bids by a second or two. Nowadays, earlier submitted short-term transmission services requests may be displaced by later ones for reasons such as higher bid price and/or longer duration of requested service. The displacement process can go on all day until the applicable deadline. The displacement based on price should result in scarce transmission capacity being awarded to those who value it the most. However, the process is ineffective in practice, since transmission price is capped at a level far below its true value at times when benchmark energy markets price differential is much higher than the cap. On the other hand, the displacement process based on duration encourages customers to make requests for service with longer duration than what they really need for their energy deals. Clearly, the first-come, first-served rule and the displacement process award scarce transmission capacity arbitrarily from an economic efficiency point of view. This rule and process do not promote the efficient use of transmission and generation resources since the customer who has won the transmission bid may have a higher energy production cost than those who lost their bids. In this case, higher cost generation will be deployed to serve load resulting in loss of social welfare.

The WTS also awards long-term transmission rights to existing customers. Awarding transmission capacity to existing customers according to when they first become customers, or on the first-come, first-served basis does not support the goals of upstream competition. The non-discriminatory transmission access principle has been further violated when new customers are asked to pay for all network upgrades, which benefit all users. Explicit transmission rights, the first-come, first-served rule, and the

WTS pricing policy in some jurisdictions have created an "unlevel" playing field for newcomers.

4.4 Summary

The discussion in this chapter demonstrates that some provisions of WTS create difficulties for open access and fail to promote efficient use of transmission and generation resources. Applying WTS pricing policy to retail access in the current BC electric industry structure will interfere with generation competition as envisaged by the Energy Plan. Past experience shows that WTS as operated is not suitable for BC's structure. The rules and business practices set out in this tariff are unworkable and inefficient. Significant changes must be made, or an innovative strategy must be implemented, to facilitate access and the efficient use of the BC Transmission System as well as generation resources.

5 OTHER POLICIES AND PRACTICES

Stand-alone transmission services are now offered across North America. These services have been created either as part of the overall electric industry restructuring or to meet FERC's requirement. Transmission access policies for the most part have been primarily based on FERC's Order 888. However, there are a few independent system operators (ISO) whose access policies and procedures have been designed to fit their specific electric industry structures. For example, the Alberta Electric System Operator conducts its business under an entirely different transmission tariff from the FERC's Pro Forma Tariff. In this chapter, the policies and practices of a few ISOs will be evaluated.

5.1 The PJM Interconnection

The PJM Interconnection was originally established as an Independent System Operator (ISO) to co-ordinate the provision of wholesale transmission services and energy trades using the Pennsylvania, New Jersey and Maryland transmission systems. Today, PJM has been recognized as a Regional Transmission Organization. The participating utilities and other transmission owners include those in all or parts of Delaware, Illinois, Maryland, New Jersey, Ohio, Pennsylvania, Virginia, West Virginia and the District of Columbia (herein referred to as the Transmission Owners.) The participating utilities continue to have the regulatory requirement or contract obligation to construct and operate their respective systems to meet the reliable electricity needs of their Native Load Customers.

Under agreements, the PJM operates a single Pro Forma Tariff to provide wholesale transmission services over the facilities of all Transmission Owners. Similar to those of BCTC, the PJM's customers are electric utilities, power marketers, generators and qualified retail consumers who meet the following criteria:

> Any retail customer taking unbundled transmission service pursuant to a state requirement that the Transmission Provider or a Transmission Owner offer the transmission service, or pursuant to a voluntary offer of such service by a Transmission Owner.[33]

Two of the many PJM's business practices are of particular interest. These are the transmission system planning process and the methodology used for allocating the costs of system expansion and enhancement.

5.1.1 PJM Long-term Transmission Planning

Under the Pro Forma Tariff, the TSP normally must perform technical studies, at the expense of the service requester, to ensure that the transmission system is capable of accommodating long-term transmission service requests. Although the rights of the requesting customer to elect to follow those study procedures in accordance with the PJM Tariff are not modified, PJM operates, at its own expense, an alternative regional transmission expansion planning process. This process is used to prepare a plan for the enhancement and expansion of the transmission facilities to meet the demands of firm transmission service safely and reliably.

[33] The PJM, PJM Open Access Transmission Tariff, May 2004, Section 1.11

The regional transmission expansion plan identifies transmission enhancements and expansions needed to meet load and generation additions over the next ten years. The planning process must take into account the participating utilities' contractual and legal/regulatory obligations.

The PJM will initiate the enhancement and expansion study process if:

- Required as a result of a need for transfer capability identified by its evaluation of the requests for interconnection or for long-term transmission service;
- Required to address a need identified by its on-going evaluation of the transmission system's economic and operational adequacy and performance;
- Required as a result of its assessment of the transmission system's compliance with the reliability criteria;
- Required as a result of generation additions or retirements, evaluation of load forecasts, or proposals for the addition of transmission facilities in the PJM region; or
- An expansion of the transmission system is proposed by one or more participating utilities or by a transmission interconnection customer.

The regional transmission plan will identify network upgrades needed to address the requirements cited above. In addition, PJM will designate one or more participating utilities or other entities to construct, own and/or finance the recommended network upgrades.

5.1.2 PJM Network Upgrades Cost Allocation

In consultation with participating utilities, other transmission owners, the market participants, and the regulators, PJM identifies cost responsibility for the system enhancement or expansion. The responsibility will be assigned to the market participant(s) based on the benefits received and the applicable provisions of the PJM Tariff. If PJM designates more than one responsible market participant, it will also designate the proportional responsibility among them. In the event that no provision of the PJM Tariff assigns cost responsibility, PJM will:

- Assign cost responsibility to market participants in one or more transmission zones based on PJM's assessment of the contributions the market participants make to the need for, and the benefits they will expect to receive from, the system enhancement or expansion; or

- Subject to FERC review and approval, incorporate costs of network upgrades to the PJM's transmission enhancement charge rate, applicable to all users, in connection with an economic expansion or enhancement.

Therefore, network upgrade costs are allocated to those who will benefit from the enhanced system, and not based on the "last draw".

5.2 Alberta Electric System Operator

In 1996, Alberta restructured the electric service industry and created two new independent entities to facilitate generation competition. These two entities are the Power Pool of Alberta (Power Pool) and the Transmission Administrator (TA). The

Power Pool is charged with the responsibility to facilitate the buying and selling of electric energy for Alberta's wholesale energy spot market. It focuses on running an open market for the exchange of electric energy and providing overall co-ordination of the Alberta provincial load and generation balance.

The TA is responsible for the planning and operation of the Alberta provincial transmission system, including the engineering and procurement of new facilities. The TA also develops and administers transmission tariff, and procures ancillary services in order to provide open transmission access to the Alberta Interconnected Electric System (AIES) for generation, retail companies, and large industrial consumers of electricity. Owning no transmission assets, the TA contracts with transmission facility owners for the use of their facilities to provide transmission services and access to the Power Pool. This arrangement is similar to BC in that BCTC utilizes BC Hydro's transmission facilities to provide access to the BC Transmission System for wholesale and retail customers.

In addition, the TA is responsible for developing long-term transmission expansion plans based on its long-term load forecasts of customer access requirements. It must justify in front of the regulator the needs for new facilities and ensure that those facilities are built in time to meet customer demand.

In 2002, the Power Pool and the TA were amalgamated to form the Alberta Electric System Operator (AESO) that essentially assumes all the roles and responsibilities of the predecessors.

5.2.1 AESO Long-term Transmission Planning

The AESO's transmission planning policy is to ensure that the customers continue to receive safe, reliable and efficient electric service wherever they are located in the province. Since transmission is by nature a long-term investment, the AESO is mandated to be forward-looking and ensure that the Alberta Transmission System capacity adequacy is sustained. It must plan and augment the transmission system in anticipating and keeping pace with forecast growth in demand throughout the province. The AESO must also operate a relatively congestion free transmission system so that the energy market can function effectively. Therefore, transmission planning and network upgrades are proactive to meet load growth and generation development.

5.2.2 AESO Cost Allocation

In Alberta, there is a long held belief that the transmission system is an infrastructure built and operated for the benefit of all users. All users, existing or new, are equally responsible for the cost of providing services at the time when the services are consumed. It is believed that existing customers who do not reduce their consumption are equally responsible for cost as those who increase their consumption. This concept has been applied to transmission costs for the entire Alberta Transmission System consisting of all major utilities in the Province sine 1982. That is, transmission costs of all utilities in the Province are pooled and allocated back to each of the utilities based on their system loads. The utilities, in turn, collect the allocated transmission costs from their retail customers. In essence, the end-users are charged for transmission services based on the total cost of the Alberta Transmission System not just the costs of their host utilities' systems. Today, the main thrust of this concept continues to dominate the AESO's cost allocation policy[34].

An application for new service can relate to a new point of delivery, supply, or an increase of an existing service point. To accommodate the service request, the AESO may need to have new transmission facilities constructed to connect the new point of delivery or supply, and to augment existing system capability. The new facilities are classified as either system-related, e.g., network upgrades, or customers related, e.g., the Direct Assignment Facilities. Consistent with the cost responsibility concept described above, system-related transmission costs are paid for by the AESO, rolled into the rate base, and recovered from all users through the standard transmission rates. No up-front customer contribution is required for network upgrades. Furthermore, system-related facilities may include facilities built to extend the boundary of the existing transmission grid, either as a result of connecting a new customer or as part of the system development plan.

In summary, cost responsibility for transmission facilities that are used by multiple customers is allocated to all users, existing and new, based on their ongoing usage of the system. This is done through the roll-in of all the system-related costs. This cost allocation policy is consistent with the notion that the transmission system is a public infrastructure. It does not discriminate among customers based on when they first connected to the system. In addition, the AESO will develop projects primarily intended for export on a case-by-case basis. The project beneficiaries would normally pay for

[34] AESO, 2003 Tariff, Terms and Conditions of Service, January 2004, Article 9

costs of such projects. Where residual benefits to the internal grid are demonstrated, the AESO may fund system upgrades, in a manner consistent with the benefits. Costs for these upgrades will be recovered from Alberta consumers.

5.2.3 AEIS Accessibility

Transmission services provided by the AESO can be group into three categories: supply transmission service for generators; demand transmission service for loads; and export and import transmission services.

Unlike WTS, which provides transmission access based on first-come, first-served, the access to transmission structure in Alberta consists of an implicit system of injection and withdrawal rights for generators and loads. There are no explicit transmission rights. Priority for service does not depend on when a service request is submitted. Transmission access applications are accommodated as soon as the required Direct Assignment Facilities are built. Export and import transmission services are provided on as available basis. Access is automatically allocated to those whose energy bids are selected by the Power Pool. This transmission capacity awarding system guarantees that those who have the lowest generation production costs, or those who have the lowest energy price bids, get the transmission capacity, and that only the most economical resources are deployed to serve customers.

5.2.4 New Transmission Development Policy[35]

In November 2003, the Electricity Business Unit of the Alberta Energy issued a new policy confirming, among other things, that transmission services will continue to be provided by a single independent entity, the AESO. Pricing for demand services continues to be based on a postage-stamp rate. This policy also advocates significant changes to the method for cost allocation to generators.

Currently, all generators are charged for delivering their energy to the market based on actual MWH output. The new policy proposes that this variable charge for generators be discontinued January 1, 2006. Transmission costs presently recovered from the generators will be allocated to the demand customers. The reason for eliminating the variable charge is that this charge increases the generators' variable costs, which in turn increases their energy bid prices into the Power Pool dollar for dollar resulting in higher hourly Pool Prices, which are charged to all energy consumption. All consumers will eventually pay for this transmission charge through higher energy prices. Therefore, the reallocation of transmission costs will not have material impacts on the load customers, and it will result in the Pool Price reflecting the true value of electric energy excluding delivery costs. The cost recovery method will provide clear transmission and generation pricing signals.

In place of the variable charge, a System Contribution Payment (the Contribution) will be implemented. The Contribution is intended to cover the network upgrade costs. However, this Contribution will apply to the new generators, but not to the existing ones.

[35] Alberta Energy, Transmission Development Policy, November 2003

Each new generator will be assessed a Contribution[36] equal to the higher of a minimum amount calculated based on its capacity and a distance-to-load related amount. Upon satisfactory operations, the Contribution will be refunded to the new generator over ten years from the commercial operation date. The refund will be rolled into the rate base and recovered from the demand customers.

This new Transmission Development Policy implies that the transmission system is planned and built for servicing loads. As such, it is deemed appropriate that costs must be borne by the demand customers. The Contribution appears to be a risk-management mechanism. It will ensure that generation owners bear the initial financial risk on costs of transmission facilities built to accommodate the new generators, and that load customers will not be burdened with the costs of uneconomical projects.

[36] For more details, please visit www.energy.gov.ab.ca/com/Electricity/Transmission/Transmission

6 STATEGY FOR BC

Based on the analysis in the previous chapters, this chapter evaluates and recommends alternative policies and business practices that best support BCTC in fulfilling its mission. These recommendations will take BCTC's mandate and the regulatory and political environment into consideration.

6.1 Planning Strategy

As discussed in Section 4.1, the responsibility for long-term planning that would identify and co-ordinate the construction of network upgrades required to serve BC Native Load and load growth has been suspended since 1997 due to business practices implemented in order to comply with the BCUC 1996 Directive. However, this directive was imposed on BC Hydro through the BCUC's Decision on BC Hydro's version of the tariff, which was abandoned when FERC refused to comment with respect to meeting the Reciprocity requirement. The 1996 Directive was a response to concerns expressed by the intervenors that the functional separation and Code of Conduct were insufficient to prevent self-dealing between the various arms of BC Hydro.

However, the 1996 Directive exempts BC Hydro from applying terms and conditions to its Native Load if "to do so is patently unreasonable."[37] It has been demonstrated that many of the WTS terms and conditions, such as the dependency of

[37] BCUC, British Columbia Hydro and Power Authority Wholesale Transmission Services Application Decision, June 1996, pg. 48

transmission planning and construction on the generation and load nomination, and contracting processes, are patently unreasonable if applied to Native Load. WTS was designed to provide wheeling services in addition to the utility's Native Load transmission requirement. In other words, it was intended for providing wholesale transmission services on the back of the utility's transmission system, planned and built to serve its Native Load. Applying these processes to Native Load removes the base on which WTS has been designed.

Moreover, WTS is now operated by BCTC, which is an independent TSP, and therefore, the concerns expressed by the intervenors are no long valid. BCTC's mandate includes, among other things, transmission system planning activities. The authority and responsibility for planning are assigned to BCTC through the Transmission Corporation Act in general, and by the Master Agreement between BC Hydro and BCTC in particular. Section 5.2 of the Agreement states:

> BCTC will have the authority and responsibility for planning, obtaining regulatory approvals for and undertaking all expansions, additions and upgrades to the Transmission System, except..., to enable BCTC to provide efficient, reliable and non-discriminatory transmission service and interconnection facilities for generation and load at 60kV and above.[38]

The following definition and standard can provide us with a better understanding of what authority and responsibility BCTC is charged with for planning the BC Transmission System.

The Western Electricity Coordinating Council defines Native Load as:

[38] Master Agreement between BC Hydro and BCTC, November 12, 2003, page 20

> [E]xisting and reasonably-forecasted customer load for which a Transmission Provider, by statute, franchise, contract or federal, state or provincial policy or regulation, has the obligation to plan, construct or operate its system to provide reliable service.[39]

And, the North American Electric Reliability Council's Planning Standards state:

> The interconnected transmission systems shall be planned, designed, and constructed such that the network can be operated to supply projected customer demands and contracted firm (non-recallable reserved) transmission services, at all demand levels,[40]...

The terms, "reasonably-forecasted customer load" and "projected customer demands", refer to the Native Load customer's future transmission requirement. The responsibility and obligation for ensuring adequate transmission capability for serving BC Native Load have been transferred to BCTC. Therefore, BCTC must plan, obtain regulatory approvals for and undertake all expansions, additions and upgrades to the BC Transmission System's main grid for serving current and future Native Load. BCTC has all the required authority and responsibility to carry out proactive planning and seek regulatory approvals for the construction of network upgrades to meet projected Native Load. This proactive process requires BCTC take a more active role in load forecasting activities. By doing so, BCTC can take full advantage of load diversity and economies of scale of the transmission system that will benefit all users and thus avoid piecemeal reinforcement. This advantage is the main reason that transmission service is considered a "natural monopoly". Transmission system investment driven by addressing service requests on a one-by-one basis is inconsistent with fully exploiting economies of scale.

[39] Western Regional Transmission Association, Governing Agreement, June 1998, page 3
[40] NERC, Planning Standards, September 1997, page 9

Therefore, a long-term transmission expansion plan produced by a proactive, forward-looking planning process is essential to operating a transmission system and business, and it will form the base for providing timely access as intended by the WTS.

Hence, it is recommended that BCTC resume the proactive, traditional long-term planning function that would identify reinforcement options, including congestion management options, and co-ordinate the construction of the network upgrades required to serve all BC Native Load customers, including those whose electric energy needs are met by IPPs.

6.2 Pricing Strategy

It is demonstrated in Chapter Four that the current pricing policies, implemented in support of WTS, resulting in different treatment for different services. In particular, the current pricing rules are inefficient in allocating costs between wheeling customers and Native Load customers. These rules, if they are applied to retail access, will have negative impacts on upstream competition within BC.

The discussion in Chapter Three shows that incremental cost pricing or efficient component-pricing should in theory be used to price wheeling services in order to ensure efficient cost allocation and avoid cross-subsidy. However, due to the unique characteristics of the transmission network, it is difficult to assign costs of common network facilities. The transmission network is an infrastructure built to support all consumption and demand patterns in aggregate, where benefits and beneficiaries of an upgrade are many and change over time. Incremental cost pricing has failed to promote timely network upgrades. Instead, it has promoted free riding. Similarly, efficient component-pricing is applicable only to short-term services, and it is difficult to implement since it is based on a utility's opportunity costs, which are non-transparent and difficult to determine.

On the other hand, average incremental cost pricing is the best candidate and recommended for Native Load, retail access and long-term wholesale-wheeling services. It is further recommended that BCTC consider using this pricing rule to design the locational pricing tariff to encourage customers to locate where cost of service is low. It is recognized that average incremental pricing may result in cost subsidization by Native Load customers in situations where network enhancement has to be accelerated to serve wheeling customers. To eliminate this cost subsidization, cost of advancement may be allocated to the wheeling customer who causes it. For example, the 10-year transmission expansion plan has identified a need for adding a series capacitor in 2008 to accommodate 400MW of Native Load growth, at a cost of $40M. In order to provide a new 100MW long-term wholesale wheeling service, this network upgrade must be installed by 2006, two years earlier than when it is needed by the Network Load customers. This means that there will be 300MW of excess capacity not required in 2006 and 2007 at a proportional cost of $30M ($40M x 300/400). To avoid subsidization by the Native Load customers, the financing cost of the $30M for the first two years should be charged to the wheeling customer. This pricing policy correctly allocates network upgrade costs to those who benefit from the system enhancement and those who cause the costs to be incurred earlier.

To ensure that transmission access is not a constraint to IPPs' ability to compete for providing electric energy to large users, it is also recommended that BCTC treat all BC customer demands as Native Load, which will be assigned the same transmission cost regardless of the energy provider. This approach will ensure that IPPs and the incumbent utility will compete to provide efficient generation on a level playing field as intended by the Energy Plan.

The recommended pricing strategy will facilitate competition for supplying electric energy within BC. At the same time, this pricing strategy is best suited for allocating costs of the transmission system, where the benefits of network upgrades are indivisible and changing over time. Average incremental cost pricing will provide consistent cost allocation to all services and all users; it will eliminate the problems of role-in network upgrade costs and free riders.

The current pricing formula used to determine short-term wholesale wheeling services is based on the assumption that energy will always flow between two pre-selected energy-markets. This assumption is far from the truth. Transmission price calculated based on this formula does not reflect the true value of the transmission system most of the time. It is recommended, instead, that BCTC consider implementing a transmission auction process to discover the true value of the scarce transmission capacity. A result of an auction will be that limited transmission capacity is awarded to those who value it the most.

6.3 Open and Timely Access

As discussed in Chapter Three, discriminatory transmission access can exist in two situations: the lack of independence of the TSP; and the explicit transmission rights granted to the users based on when they first become the customers. The first problem has been resolved in BC with the creation of BCTC. To fully address the transmission rights concern and to maximize social welfare, transmission access will have to be awarded each and every time to the most efficient generation resource, which will be deployed to serve load. In addition, transmission system needs to be planned and built to accommodate all load demands. With this approach, transmission investments will be risky, unless there is certainty that demand will always be there. For Native Load, demand is unlikely to vary significantly over a short time, and therefore, this approach can be implemented with little risk. The planning strategy and pricing strategy, specifically the treatment of all loads within BC as Native Load, recommended in the preceding sections will go a long way to ensure such a desired outcome. For off-system sales or wholesale wheeling, however, the export market is large and volatile. It is unreasonable to expect any TSP to plan and build transmission to accommodate all export demands based on forecast, but it is reasonable to expect that a TSP adjust its long-term transmission expansion plan to provide long-term wholesale wheeling services.

In summary, the planning strategy and pricing strategy recommended will facilitate open access and promote efficient use of the provincial grid for serving Native Load in a timely manner. These strategies will also improve access for wholesale wheeling at prices that are consistent with efficient pricing principles. They will also eliminate cross-subsidization between Native Load customers and wholesale wheeling customers, and they will make free riders a thing of the past.

6.4 Implementation Issues

To implement the recommended strategies, BCTC will need to address the resource requirements and business processes. Implementation of these strategies will have significant impacts on the following areas: System Performance Assessment, Pricing, Regulatory, Congestion Management and Load Forecast.

6.4.1 System Performance Assessment

System Performance Assessment's (SPA) responsibilities include:

- Conducting studies of the power system to support the derivation of operating guidance and advice for Real-time Operations; and
- Conducting long-term planning studies and analyses to determine the economic enhancements and what will be required to meet the changing regulatory requirements, the growing and changing demand of customers, and the changing condition of the existing equipment.

The recommended planning strategy fits SPA's responsibility areas, specifically in the area of "growing and changing demand". SPA's resources have been stretched really thin due to the ongoing operating issues of a congested system, and the deluge of transmission interconnection and service requests. The effort spent on system studies in response to these requests does not contribute much benefit to the overall system expansion plan, since these studies address specific issues related to individual requests.

SPA needs to focus its effort on proactive, long-term planning issues to ensure system adequacy to meet projected Native Load growth.

In addition, the pricing strategy will demand more support from SPA. Since average incremental cost pricing requires up-to-date information on replacement costs of existing equipment and, to a certain extent, new system configuration, SPA will have to design new and more efficient system configurations so that accurate average incremental cost can be determined. This design work is needed because the transmission system is enhanced over time in response to gradual load increases. The resulting system configuration is not the same and not as efficient as a system designed today to meet current demand level. Moreover, the locational pricing based on average incremental cost will require SPA to do similar design work.

To support both the planning and pricing strategies, BCTC can consider the following actions:

- Increase SPA engineering staff;
- Redefine long-term system expansion planning and operation planning activities, since results from these two areas have different implications, and require different focuses.

6.4.2 Pricing

BCTC does not have internal pricing capability at this time. BCTC will need to acquire services from pricing professionals with a deep understanding of the transmission business and, particularly, transmission system characteristics. Areas that need to be addressed, for example, are:

- Transmission pricing policies, including early investment policy;
- Average incremental cost pricing design; and
- Locational pricing design.

6.4.3 Regulatory

BCTC will need to view the BCUC's 1996 Directive with the regulator, and seek necessary approvals for implementing the recommended strategies.

6.4.4 Congestion Management and Load Forecast

Congestion management could be more economical than building network upgrades, and therefore BCTC should pursue congestion management solutions as part of its system expansion planning activities. Currently, BCTC does not have a significant focus in this area. BCTC needs to increase its capability in congestion management.

The recommended planning strategy requires BCTC take on the responsibility for planning and co-ordinating the construction of network upgrades to meet projected Native Load based on its forecast. Current capability in this area must be reviewed to ensure BCTC has the required expertise to fulfil this essential responsibility.

6.4.5 General Issues

In a competitive environment, customers pressure BCTC to cut its cost. It will therefore be a challenge for BCTC to hire the necessary resources to support the implementation of the recommended strategies. While customers are demanding that BCTC reduce technical study costs, BCTC must resist, since reducing technical study efforts will actually lead to higher overall transmission costs in the long run. As study costs cover only the costs of engineering time, a higher cost means engineers spend more time to do thorough investigations, which could result in finding more economical solutions. For example, a system planning study that can find ways to delay a major reinforcement project by one year can save ten of millions, a trade off between low-cost knowledge asset and high-cost physical asset. Therefore, an increase human capital is a sensible strategy for ensuring low overall transmission cost in the long run.

7 SUMMARY AND CONCLUSION

The discussion in Chapter Three provides generic concepts for efficient planning, pricing principles and business practices that facilitate access and promote efficient use of common facilities for wholesale competition in general, and electric energy industry in particular.

An electric transmission system has large minimum efficiency scale and enormous overall economies of scale. To take advantage of the benefits of economies of scale, transmission capacity must be identified and constructed to satisfy long-term requirements in the aggregate. This is the main reason that transmission service is considered a natural monopoly. Therefore, it is imperative that transmission system planning must be proactive and forward-looking.

Economies of scale along with the unique characteristics of a dynamic AC grid, where benefits and beneficiaries of an upgrade are many, difficult to identify, change over time and widely used, make it difficult to assign costs of network upgrades to specific uses or users. In this context, average incremental cost pricing is suited for long-term transmission services. On the other hand, when there is insufficient capacity to accommodate both the utility's and its competitor's energy transactions, or when they are competing for the same sale, an auction process may be used to discover the true value of the scarce transmission capacity. The auction process will ensure the limited transmission capacity is awarded to those who value it the most.

In addition, since the transmission system is the "energy highway" used for facilitating competition in generating electrical power, access to scarce transmission capacity should be granted to whoever can produce the power most efficiently at any given time. This approach will create a level playing field for all generators. It will ensure that only the most efficient generation is deployed to serve load, and thus maximize social welfare, an outcome that the first come, first served rule will not provide.

The analysis in Chapter Four shows that the current WTS and pricing policies as implemented have significant shortcomings. WTS has been designed on the basis that utilities' will continue to have their statutory, franchise, or contractual obligations to plan, construct and operate their respective systems to provide reliable service to their Native Load customers. The implementation of the BCUC's 1996 Directive has removed the foundation on which WTS was built, leading to the suspension of the traditional long-term planning function, and the adoption of the WTS service request process. As a result, no major transmission facility has been built in years.

Some provisions of WTS create difficulties for open access and fail to promote efficient use of transmission and generation resources. Past experience shows that WTS as operated is not suitable for BC's structure. The rules and business practices set out in the existing tariffs are unworkable and inefficient, resulting in different treatment for role-in of network upgrade costs for different services when network upgrades are involved. In addition, the "higher of rule" and the incremental pricing principle encourage free riders, as these pricing policies allocate all network upgrade costs to the "last straw" even though the upgrades benefit existing as well as future customers. Moreover, applying current pricing policy to retail access in the current BC electric industry structure will interfere with generation competition as envisaged by the Energy Plan.

A review of practices and policies adopted by other TSPs shows that they continue to take a proactive, forward-looking transmission planning function. It also shows that costs of network upgrades are assigned in accordance with benefits received as well as cost causation. Where indivisible benefits are derived from the construction of common facilities, costs are rolled into the rate base and paid for by all system users.

Therefore, it is recommended that BCTC seek necessary regulator approvals for implementing the following strategies for facilitating open access and promoting the efficient use of the provincial transmission grid:

Planning Strategies

- To take a proactive, forward-looking planning function that would identify reinforcement options, including congestion management options; and

- To obtain regulatory approvals for and undertake all expansions, additions and upgrades to the BC Transmission System's main grid for serving current and future Native Load customers, including those whose electric energy needs are met by IPPs on a proactive basis; and

- To adjust the long-term transmission expansion plan to provide long-term wholesale wheeling services.

Pricing Strategies

- To design and implement average incremental cost pricing policy for assigning transmission costs to Native Load, retail access and long-term wholesale-wheeling services;
- To design and implement locational pricing based on average incremental pricing rule to encourage customers to locate where cost of service is low;
- To design and implement early investment policy to allocate cost of advancement of network upgrades to the wheeling customer who causes it in order to eliminate cost subsidy by Native Load customers;
- To design and implement a transmission auction process to discover the true value of the scarce transmission capacity, and to award limited transmission capacity to those who value it the most; and
- To treat all BC customer demands as Native Load, regardless of the energy provider, to ensure that IPPs and the incumbent utility compete to provide efficient generation on a level playing field as intended by the Energy Plan.

REFERENCE LIST

AESO, 2003 Tariff, Terms and Conditions of Service, January 2004

Alberta Energy, Transmission Development Policy, November 2003

Baumol, William & Sidak, Gregory , Transmission Pricing and Stranded Costs in the Electric Power Industry, the American Enterprise Institute, Washington, D.C., 1995

BC Hydro, BC Hydro 2004/2005 & 2005/2006 Revenue Requirement Application, December 2003

BC Hydro, Wholesale Transmission Service Tariff, June 1997

BCTC, Board of Directors Strategy Retreat, April 2004

BCUC, British Columbia Hydro and Power Authority Wholesale Transmission Services Application Decision, June 1996

FERC, Large Generator Interconnection Agreements & Procedures, July 2003

FERC, Order 2000: Regional Transmission Organization, December 2000

FERC, Order 888, April 1996

FERC, Order 889, November 1997

FERC, Standard Market Design Notice of Rulemaking, July 2002

FERC, Standardization of Generator Interconnection Agreement & Procedures NOPR, April 2002

Hydro Quebec, Comparison of Electricity Prices in Major North Cities, May 1998

Master Agreement between BC Hydro and BCTC, November 12, 2003

NERC, Planning Standards, September 1997

The PJM, PJM Open Access Transmission Tariff, May 2004

The Province of British Columbia, Energy for Our Future: A Plan for BC, November 2002

The Province of British Columbia, Transmission Corporate Act - Bill 39, May 2003

Transmission Access Policy Study Group, Effective Solutions for Getting Needed Transmission Built at Reasonable Cost, June 2004

Western Regional Transmission Association, Governing Agreement, June 1998