EVALUATING THREE ALTERNATIVES FOR PROPOSED ELECTRICAL TRANSMISSION LINES TO SOUTHERN VANCOUVER ISLAND

by

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ABSTRACT

This study evaluates three proposed alternative electrical transmission projects to Vancouver Island in terms of financial and non-financial characteristics. The three proposals differ in financing, technology, route, and regulatory frameworks. For establishing reliability and meeting future electricity needs, the Vancouver Island Transmission Reinforcement (VITR) Project is the least costly alternative, but will likely not be operational to meet the required in-service date and may encounter continued opposition from special interest groups. The Juan de Fuca (JDF) Project could likely be completed on time, and provide both reliability benefits and export potential. A preliminary financial analyses indicate that the VITR and JDF Projects are complementary; if both projects are constructed, net present value of the benefit to BC Ratepayer/Taxpayers is between \$50 and \$450 million. The JDF Project would also allow BC Hydro to avoid transmission congestion near Seattle, and thus increase the efficiency of electricity trade with the Pacific Northwest.

DEDICATION

For my wondrous Sasha, and the start of a time for us.

ACKNOWLEDGEMENTS

This comprehensive study is the result of teamwork, insights, and perseverance.

James Griffiths effectively managed and compiled all the information in the British Columbia Utilities Commission regarding the Vancouver Island Transmission Reinforcement Project. The accessibility of the material was a key element the research that was required for this study.

The technical team at Sea Breeze provided answers to my questions regarding electrical transmission systems, project financing, and regulatory issues. This interaction was fundamental to developing the ideas in this study.

Insights into the analyses for this study were provided by the Sea Breeze team, as well as questions and comments Dr. Ed Bukszar and Dr. Neil Abramson. It is not possible to effectively analyze the issues without looking at the broad context.

Lastly, perseverance is only possible if time is available. The support from Sasha, my family, friends, as well as my co-workers and MBA team made the Program and this research an incredibly rewarding experience.

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1 INTRODUCTION

Electrical transmission lines form networks that connect generation facilities with customers. Bulk transmission systems are designed to carry large power flows over long distances, and are generally recognized as high voltage lines of 230kV or greater that link large sources of generation with smaller distribution systems for retail and export customers (Figure 1). In British Columbia, the incumbent utility is BC Hydro which uses its large hydroelectric reservoirs to arbitrage electricity and creates considerable revenues through energy banking[1] for the Province. For example, in March 2006, the BC Hydro generated an estimated $256 million in revenue through 2005, even though the province was a net importer of electricity (BC Stats Infoline, 2006). Transmission systems are a fundamental component for serving both retail customers and generating revenue through sales to export customers.

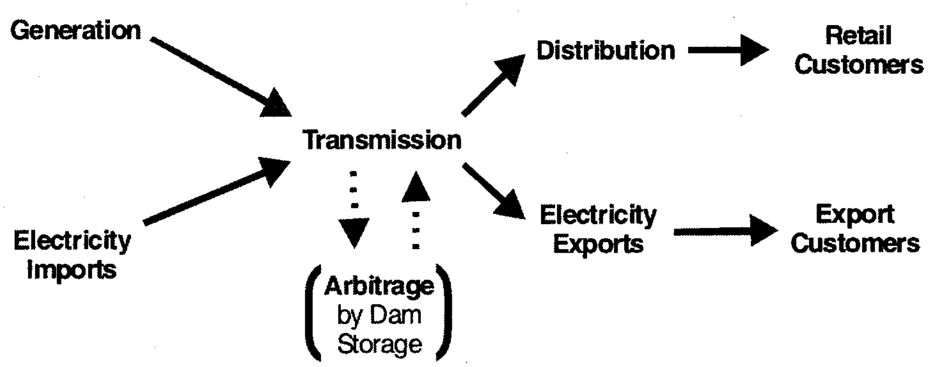

Figure 1: The structure of the electricity industry in British Columbia

[1] Energy banking involves importing electricity when prices are low and using this as a substitute to supply load for generation from hydroelectric reservoirs. The water that is stored during this time is later released for export at a price higher than that paid for imports.

Transmission lines must meet two broad sets of criteria. The first is related to capacity, defined as the adequacy to deliver electrical power at times of peak demand. The second set of criteria relate to reliability, also known as the ability of the transmission system to remain in service following natural disasters (such as earthquakes, extreme snow loads, forest fires, etc.) or during times of scheduled maintenance. Capacity and reliability are two objectives in planning new transmission projects.

The amount of needed capacity is determined by load forecasts, typically carried out by an existing utilities. For example, BC Hydro regularly carries out load forecasts as a planning requirement, and develops plans for long term acquisition in light of existing generation sources and others that could well be available. The Integrated Electricity Plan and the Long Term Acquisition Plan developed by BC Hydro were recently presented for approval to the British Columbia Utilities Commission (BCUC) and the government (BC Hydro, 2006a). These plans discuss the generation and transmission requirements to meet the needs of the province over the next 20 years. This information regarding the requirements for capacity is used in system planning for the transmission system.

The requirements for reliability are set by the National Electricity Reliability Council (NERC) that provides guidelines for electrical system planning objectives to meet specific "contingencies" or outage situations (Brown and Sedano, 2004). Transmission utilities throughout North America follow these standards on a voluntary basis; however, since the East Coast Blackout of August 2003, strong policy statements suggest these standards will become mandatory for all US utilities.

This chapter discusses electrical transmission in terms of its natural monopoly characteristics, the role of private investment, and introduces the three projects that are the subject of this thesis.

1.1 Characteristics of Electrical Transmission

In the early 1990's, the Federal Energy Regulatory Commission (FERC) required the separation of electrical transmission from generation and distribution as a means to support the competitive wholesale market for electricity. This section discusses the characteristics of electrical transmission as a natural monopoly, and the emerging role of private investment in the development of transmission infrastructure.

1.1.1 Electrical Transmission Lines as a Natural Monopoly

Electrical transmission systems were often considered a natural monopoly due to their very significant economies of scale during operation and the lumpy capital costs of expansion. As discussed by Joskow and Tirole (2005), in many cases it is not practical or feasible to construct transmission facilities that meet only the marginal demands for transmission capacity. This is particularly true due to the fluctuating transmission capacity that is needed on an hourly, daily, and seasonal basis.

Given the strong natural monopoly characteristics, electrical transmission lines are typically regulated, with government oversight regarding the overall need and necessity for the construction of new facilities as well as environmental permit approvals.

As with many natural monopolies, there has been an undersupply of transmission infrastructure for the electricity market. For the US, Hirst (2004) discusses many of the factors that have shaped this situation: the increased load growth, particularly in light of retiring of generation sources and population growth in new areas; the aging infrastructure throughout the US; and the increasing use of the transmission system for trade causing "congestion" - times when transmission system capacity cannot meet peak demand. Hirst also concludes the numerous utilities (both investor-owned and public entities) represent an additional challenge to building new transmission infrastructure, particularly if individual utilities seek the benefits of free-riding on transmission projects that are implemented by others.

Within BC, the British Columbia Transmission Corporation (BCTC) provides the planning, construction, and operation of the bulk electrical transmission system for the province. The assets are owned by BC Hydro. BCTC provides the services related to energy delivery and collects the associated tariff revenues, as well as a set of ancillary services[2] (including reactive power[3]) for the reliable operation of the transmission network. In the last two decades, relatively few transmission lines were constructed in BC. However, recent plans submitted by both BCTC and BC Hydro indicate that several new transmission lines are needed in the province to meet the growing demand for electricity and increase the reliability of the existing transmission system (BC Hydro, 2006a).

1.1.2 A Role for Private Electrical Transmission Development

Privately-funded development has been touted as the most effective means to bring the innovation, technology, and risk tolerant aspects of the private sector and expand the transmission system (Hirst, 2004). Private development may occur as a completely private endeavour for the construction and operation of a merchant transmission line, or as a public-private partnership project (also known as a "P3 project"). The typical parties to a private financing arrangement are: 1) the sponsor, a transmission development company; 2) the equity partner that provides the initial funding for development in exchange for partial ownership; and 3) the debt partner that provides most of the financing in exchange for a stable cash flow and expected rate of return (Nevitt and Fabozzi, 2000).

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[2] Ancillary services include: scheduling and dispatch for the movement of both real and reactive power; regulation of alternating current frequency; correcting energy imbalances; monitoring operating reserves (both spinning and supplemental); and monitoring of transmission losses.

[3] Reactive power complements real power, which is the electricity that is transmitted and consumed on the electrical system. A continuous balance of reactive and real power is fundamentally important aspect to the stability of a transmission system.

The lack of newer transmission infrastructure is the result of many incumbent utilities not having the funds to invest, partially because of historically low rates of return and partly because of the instability within the energy markets in the early 2000's (Joskow and Tirole, 2005). This situation appears to be changing, and recent studies of transmission plans conclude the required investment must increase considerably (EASI, 2005). Some of these projects are expected to be funded through private investment, and some will be merchant projects that operate on a toll basis, while others will be operated as part of the incumbent utility's transmission system.

The importance of private investment has, in broad terms, both government support and the interest of the private sector. The FERC has provided a number of incentives and market signals relating to the private investment of transmission lines, such as precedent-setting approvals for merchant transmission projects and regulatory streamlining that are intended to incent investment and development in a timely manner. Regarding the private sector, the gradual removal of regulatory barriers has provided attractive investment opportunities for several reasons, including: the size and stability of electrical demand; federal legislation building on earlier regulatory changes to enhance a competition in the electricity market; the regional and fragmented nature of the industry; the long-standing underinvestment; industry cost restructuring; and supply/demand imbalances due to geographic transmission constraints (AltAssets, 2004). Investment companies that specialize in the energy industry may be well positioned to take advantage of the regulatory and structural changes in the market.

1.2 Project Proposals for Vancouver Island Transmission

1.2.1 Transmission Justification

Most of the 2200MW of electricity required for Vancouver Island flows through two main transmission lines that cross from the mainland north of Sechelt and connect to central Vancouver Island near Courtneay (BCTC, 2005a). On-island generation meets only 15 percent of the required electricity demand. An older high voltage direct current (HVDC) transmission line, connecting Delta with Duncan is currently providing some transmission to meet peak loads. However, due to the age of the system, the HVDC line will be derated[4] in winter, 2006 and considered completely unreliable in fall, 2008. This HVDC line accounts for approximately 240MW of transmission capacity. BC Hydro and BCTC are currently investigating temporary measures to make up for this shortfall (BC Hydro, 2006b).

Considerable efforts were made to develop generation on Vancouver Island. In the early 1990's, BC Hydro examined the potential for improving the transmission links with Vancouver Island, and examined a number of potential routes associated with existing corridors. Virtually all options were rejected due to formidable construction conditions (BC Hydro, 2004a). In the The GSX Pipeline was proposed to transport natural gas from Cherry Point in Washington State to Duncan on southern Vancouver Island, and BC Hydro proposed a natural gas turbine plant in Nanaimo to meet peak loads. In spring 2004, BC Hydro decided to withdraw the project and start reviewing options for additional transmission (BC Hydro, 2004b).

1.2.2 Project Alternatives

Three transmission alternatives for meeting the required peak loads on Vancouver Island were examined as part of the British Columbia Utilities Commission (BCUC) Proceeding on the Vancouver Island Reinforcement (VITR) Project from July 2005 to July 2006. The proposals differ in terms of their technology, regulatory frameworks, and involvement of the private sector.

The VITR Project was a proposal from the British Columbia Transmission Corporation (BCTC) to link Delta with Duncan following existing transmission corridors across Georgia Strait and the Gulf Islands (BCTC, 2005a). This project would utilize existing high voltage alternating current (HVAC) technology, which is well understood and common throughout North America.

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[4] "derating" involves studies to determine the reliability of a transmission line or its components, and then use a lesser capacity limit due to the age of the facility or inadequate back-up facilities if appropriate

The second proposal was the Vancouver Island Cable (VIC) Project, put forward by Sea Breeze Pacific, a private company (Sea Breeze, 2005a). The VIC Project would utilize newer high voltage direct current (HVDC) technology, and follow existing utility corridors and streets. For the marine areas, the project would use a significant portion of the route studied for the GSX Project[5] to connect Surrey with Victoria.

The third was the Juan de Fuca Cable (JDF) Project, also put forward by Sea Breeze Pacific (Sea Breeze, 2005b). This proposal was for an international power line to link Greater Victoria with Port Angeles on the Olympic Peninsula, using the same HVDC Light® technology as the VIC Project.

1.2.3 Regional Context

It is important to consider the regional context of the transmission system in the Puget Sound and Southern Vancouver Island (Figure 2) regarding the three transmission project alternatives. The existing transmission systems to Greater Victoria and Port Angeles are at the distal ends of their respective networks. Such a configuration often causes voltage stability problems, and fluctuations in the AC frequency must be controlled. Both BCTC on Vancouver Island and Bonneville Power Authority (BPA) in Washington State operate facilities to stabilize the grids on their respective systems to ensure system reliability.

In terms of export, the existing transmission lines that run south from Surrey to Puget Sound are the main interconnection between BC and Alberta and Washington State (Figure 2), known as the Blaine Intertie. This transmission line and the system immediately south, known as the I-5 Corridor, form a link that is absolutely vital for electricity trade between western Canada

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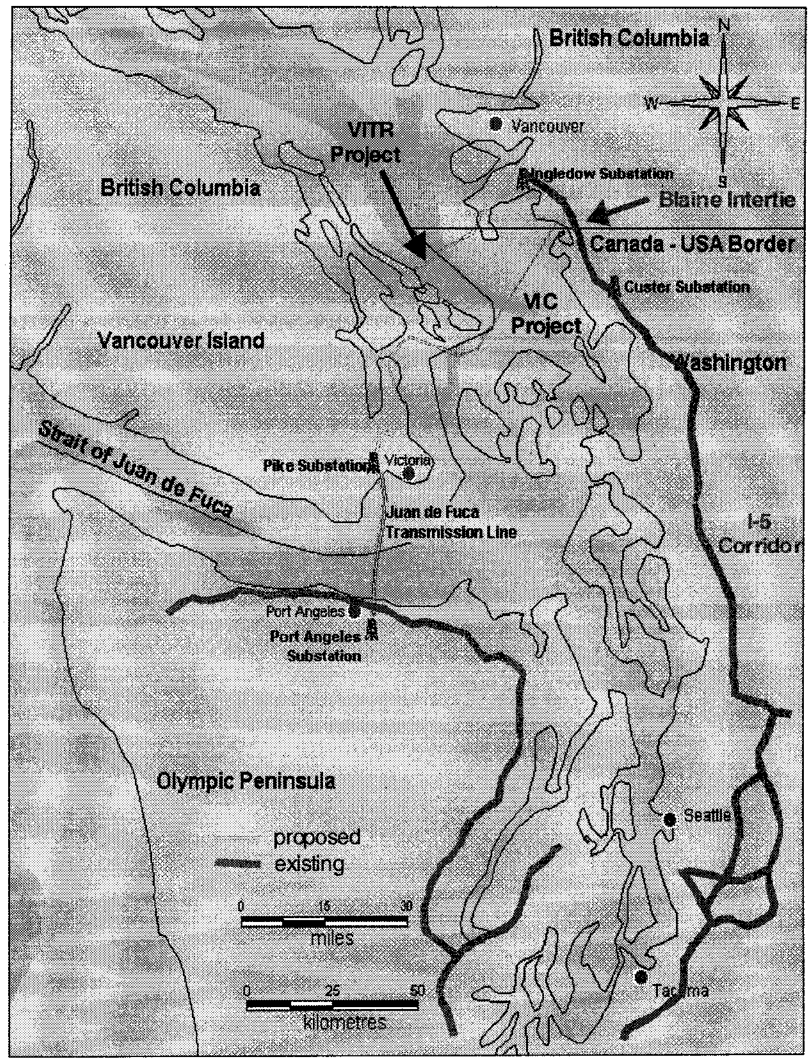
[5] The investigation for the GSX Pipeline project was carried out and met the requirements of the Canadian Environmental Assessment Act (CEAA) for installation along the marine route. The GSX Project was successful in obtaining its approvals, but was cancelled by BC Hydro along with the Duke Point Project.

and the US, carrying 85 to 90 percent of the BC electricity trade (BC Stats Infoline, 2006 and BC Hydro, 2006b).

The transmission system in Washington, Oregon, and Idaho is operated by the Bonneville Power Authority (BPA). There is an increasing amount of congestion on the BPA transmission system, and a recent study indicates that there are often curtailments where energy generators or



Note: Approximate locations of transmission lines adapted from BPA, 2002.

Figure 2: Options for transmission reinforcement to Vancouver Island and regional transmission (adapted from Sea Breeze, 2005a and Sea Breeze, 2005b with permission).

marketers are not able to obtain scheduled service on the BPA system due to operations at peak loads (BPA, 2006a). The congestion is particularly problematic around the Seattle area, where a recent agreement between the municipal utilities in the area, BPA, and Powerex (the energy marketing subsidiary of BC Hydro) shared an agreement to reduce schedule conflicts for electricity flow northward to Canada. Given the Columbia River Treaty and the Canadian Entitlement[6] (also known as the "Downstream Benefits") that BPA is required to return to Canada (BPA, 2006a), the transmission of this power northwards on the I-5 corridor exceeds the capacity of the system. Although the Canadian Entitlement is often sold into the wholesale electricity market in the US, there is an increasing need to bring the power north as one part of the BC domestic electricity supply (BC Hydro, 2006a). A recent study by the US Department of Energy on transmission congestion in the US also highlighted the I-5 corridor and the Puget Sound area as a "critical" location for future transmission improvements (Figure 3), and the existing transmission paths between BC and Washington are shown as congested. There is also significant congestion east-west through Washington and Oregon, such that generation from the east cannot always reach the load centres in the western part of the states.

[6] The Canadian Entitlement is the result of the Columbia River Treaty whereby BC constructed three dams on the Columbia River (Mica, Duncan, and Keenleyside) in return for half of the additional electricity (about 540 aMW) that is generated on a number of Columbia River dams in the US. The construction of the Canadian dams created significant downstream benefits due to the regulation of river flow. Canada agreed to sell the Canadian Entitlement into the US market. However, on March 31, 2003 this agreement expired, and BPA was required to return the benefits to Canada. As a result, BPA has constructed several transmission projects with the partial objective of returning the Canadian Entitlement to BC (ZE PowerGroup Inc., 2005).

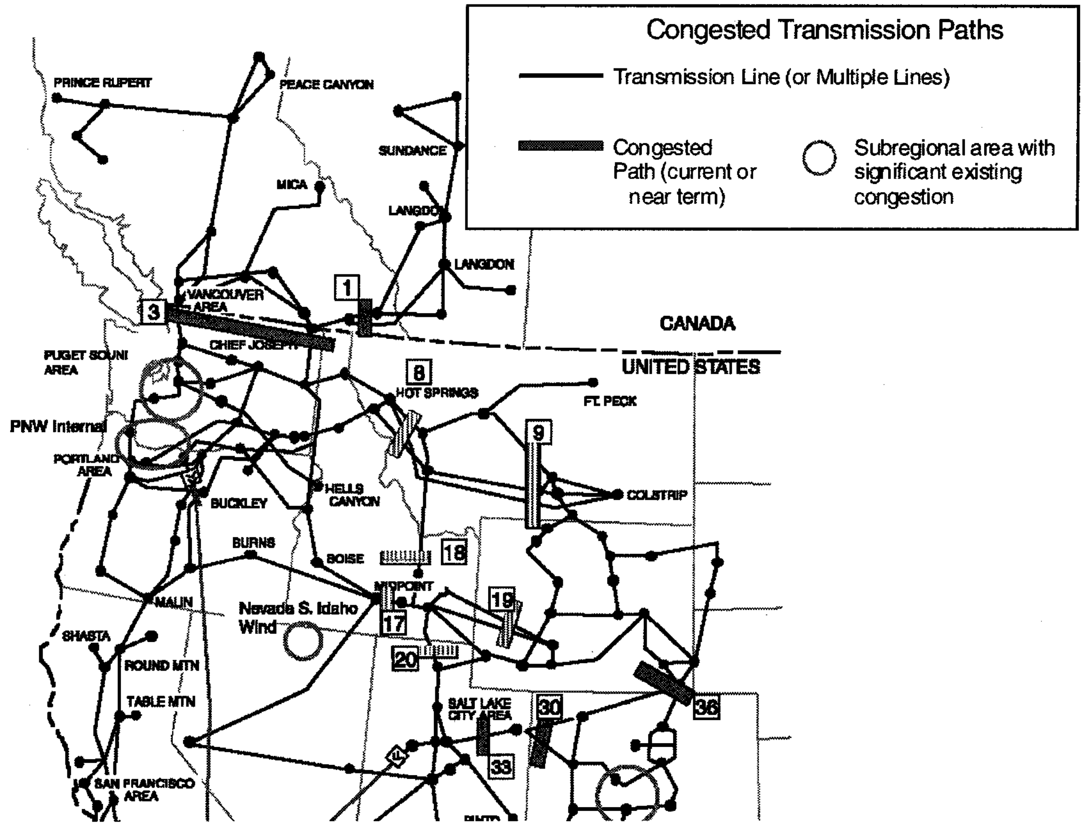


Figure 3: Transmission lines in the BC and the Pacific Northwest (DOE, 2006 with permission)

1.3 Scope of Thesis

The three alternatives for additional transmission to southern Vancouver Island – the Vancouver Island Transmission Reinforcement (VITR) Project, the Vancouver Island Cable (VIC) Project, and the Juan de Fuca (JDF) Project - represent a unique opportunity to evaluate private and public projects with respect to technology, regulatory, and financial aspects in a regional context. The trends in the transmission industry, non-financial criteria such as reliability, and financial criteria such as cost and indirect benefits must be considered in the evaluation of these alternatives. Market and industry trends also influence specific aspects of the projects.

In brief, the structure of this thesis is as follows.

Chapter 2 provides a discussion of the transmission industry, particularly relating to regulatory frameworks and the industry and market forces that affect both public and private transmission projects.

Chapter 3 discusses the VITR, VIC, and JDF Projects in detail, including the technology, route, financing, and implementation considerations.

Chapter 4 compares and ranks the non-financial aspects of the projects, such as public health, accidents / malfunctions, operational reliability, and permitting timelines. Subjective probabilities are used as a means to evaluate the likelihood of each project of meeting established thresholds.

Chapter 5 calculates the total direct and indirect costs as a basis for comparing the projects to determine which of the three is the least cost alternative, from both a reliability and export perspective. Probability distribution functions are used as a means to incorporate uncertainty into the analyses. The comparison also includes the benefits, as the VIC and JDF Projects provide benefits (avoided present or future costs) that cannot be realized with the VITR Project.

Chapter 6 provides a discussion of the results in Chapters 4 and 5, and the implications of increased electrical trade relative to the projects and the regional transmission system. Chapter 6 also presents the conclusions and recommendations for further research to investigate the transmission projects in the context of the regional needs of the Pacific Northwest.

2 TRANSMISSION INDUSTRY ANALYSES

2.1 Size and Structure of the Transmission Development Industry

Transmission represents about 10 percent of the total utility assets in the United States, with an estimated worth of $80 billion[7] (Krellenstein, 2004). Many studies indicate the need for significant increases in transmission investment following decades of underinvestment. EASI (2005) suggests an annual decrease of $115 million in transmission investment over the past 25 years, and documents 304 new transmission line projects which are expected to increase the national grid for a total length of 15,330 km with an increase of about $10 billion from 2004 to 2008. Roseman (2005) notes this represents an increase of 60 percent for investor-owned utilities in the US. In the longer term, an estimated $50 billion is needed for transmission infrastructure by 2030, with about 75 percent required for maintenance and upgrade of the existing systems and 25 percent for the construction of new facilities. The size of the transmission industry, particularly development, is growing rapidly.

The structure of the transmission development industry is defined largely by the role of incumbent utilities in the types of projects that are required and the steps for project development.

2.1.1 Type and Scope of Projects

Transmission development is generally carried out by either incumbent utilities (operating within a given jurisdiction) or private developers (operating independently within or between different jurisdictions). Development generally falls into two categories: system upgrades, which relate to replacing specific components of the transmission system to improve its

[7] This asset base is spread over transmission companies with differing rate structures and policies, including investor-owned utilities, public utilities, US Federal utilities, and cooperative utilities.

performance, and network expansion which involves the construction of new transmission lines to improve capacity and/or reliability. Table 1 illustrates the typical roles for incumbent utilities and private developers.

Transmission lines that are developed between jurisdictions can be 'merchant' lines as they are financed on the basis of toll contracts. EASI (2005) notes the pre-disposition of transmission development to either private/merchant or public/incumbent companies. Specifically, private development is most likely to take place if the differences in electricity prices between two jurisdictions are "pronounced and endearing". Development within the jurisdiction of a single incumbent utility can require a greater level of cooperation and coordination for private development projects. Table 1 summarizes the relationship between project scope and project type for private and incumbent development.

Table 1: Project Type and Project Scope for Transmission Development

		Project Scope[1]	
		Intra-Jurisdictional	Inter-Jurisdictional
Project Type[2]	System Upgrades (new equipment on existing system)	***Incumbent Utility*** suited to lead project. Requires integration of planning and implementation with existing facilities.	Applicable to very few projects. ***Private Developer*** may act as Consultant or Liaison with Incumbent Utilities to develop project.
	Network Expansion (project increases footprint of network)	***Incumbent Utility*** may partner with ***Private Developer*** in a P3 (Public-Private Partnership) model to plan, design, and implement project.	***Private Developer*** likely to initiate, plan, design, build, and realize revenues from operation (merchant project). Works with adjacent Incumbent Utilities for interconnection.

Notes:

1. *Jurisdiction refers to the control area (operation area) of the* ***Incumbent Utility****.*
2. *Joskow and Tirole (2005) refer to System Upgrades as "Network Deepening" investments.*

2.1.2 Steps for Transmission Project Development

The development of transmission projects, both by private companies and incumbent utilities, follows a common set of phases (Table 2). These start with the identification and development of the concept, through to permitting for a Certificate of Public Need and Necessity (CPCN) and environmental studies, to contract negotiation, construction, and finally operation.

Table 2: Description of typical phases for transmission line development

Project Phase	Description
Concept development	***Definition of the project:*** a) designating end-points, and their associated market conditions; b) identifying the preferred technology; c) selecting route alternatives; d) estimating project costs and revenures; and e) determining project timelines
Feasibility Studies	***Assessment of the project concept:*** review market conditions/justification, financing, regulatory issues, as well as technical and environmental constraints
CPCN Permitting	***Preparation of application:*** review by government agencies to determine need and necessity; includes consultation with key stakeholders and public, and may include reviews of environmental studies as well as budgeting and financing[1]
Preliminary Engineering	***Review of technical issues:*** evaluation of technical aspects of project; carried out to identify critical technical issues arising out of feasibility studies and environmental permitting
Environmental Permitting	***Review of environmental issues:*** public and First Nations consultation and evaluation of environmental impacts of the project; carried out to obtain approvals from various government agencies
Budgeting, Financing, Service Contracts	***Negotiation of service contracts:*** financial analysis, detailed budgeting, and securing contacts with generation companies and others for transmission capacity and other aspects of the completed project
EPC Contract	***Negotiation with manufacturer/supplier:*** develop detailed specifications and scheduling for manufacturing
Final Engineering Design	***Design to meet technical/environmental objectives:*** final design of project to meet the objectives identified in earlier studies. Can be carried out as a design-build contract to quickly integrate technology requirements with construction phase
Construction	***Construction of facility:*** line installation and interconnection with existing facilities
Operation and Maintenance	***Operation of facility:*** use of facility as part of transmission system, maintenance as required to address technical and environmental issues during operation

Note: 1. The CPCN Application may contain detailed cost and finance information if the incumbent utility is a public utility subject to regular reviews by government agencies, as is the case with the British Columbia Utilities Commission (BCUC) to determine the cost to ratepayers. See Chapter 4 for analyses of ratepayer impacts.

2.2 Regulatory Aspects

The multitude of regulatory requirements for permitting electrical transmission lines significantly contributes to the complexity in development. In general terms, the regulatory framework for the review and approval of transmission lines includes federal, provincial/state, as well as local components. These reviews and approvals include all aspects of transmission line projects, including the granting of market authority[8], the compliance with all environmental legislation, as well as socio-economic evaluations involving the key stakeholders and the general public.

2.2.1 Federal Reviews and Approvals

2.2.1.1 Federal Electrical Regulatory Commission (FERC)

Federal jurisdiction for transmission lines differs slightly for Canada and the United States. Joskow (2005), in a review of US transmission policy, concluded that the shift towards the deregulation of the transmission system in terms of access, pricing, and investment was not sufficient to overcome the balkanized structure and patchwork of investor-owned and public utilities in large regions. The intent of the FERC regulations in the 1990's was to increase investment in transmission and support the competitive market established for wholesale electricity. After a few notable exceptions (such as the competitive market in the Northeastern US) and several significant failures (such as Enron and the California Crisis), the transmission system remains fragmented due to regional political and market issues even with the

[8] Market authority for a merchant project is the legal right to charge tolls for services. For a regulated project, market authority involves obtaining approval for a specific rate of return from a regulatory body.

implementation of Open Access tariffs and incentives for regional transmission planning. Table 3 summarizes the changes in transmission regulatory policy in the US.

The concept of deferrals is one example of how FERC has introduced incentives for private investment in generation and transmission infrastructure. FERC Order 2003-A includes provisions for third parties to claim a portion of the "avoided cost" or direct costs of a project that is planned. Thus, deferrals can be claimed by merchant transmission companies if a proposal for private transmission can be developed for less than the previously planned generation or transmission project. Many utilities are still adapting these requirements (BPA, 2004b).

The 2005 US Energy Act provides some specific regulatory changes for electrical transmission. Specifically, the federal Department of Energy will study transmission corridors and identify ones that are in the national interest for upgrades or new construction. The FERC was also given the authority to review and override state decisions regarding specific transmission lines if the state fails to grant approval within one year after the application. The FERC is also now required to consider higher rates of return for transmission investment, including higher returns on equity and financial incentives to reduce congestion. Qualified transmission facilities were also granted accelerated depreciation over 15 years rather than the previous 20 years as an incentive for investment (ICF, 2005).

The jurisdiction of the FERC has two impacts for Canadian utilities. The first relates to reciprocity, and Order 899 which requires any utility that uses the facilities of US investor-owned utilities for transmission must comply with FERC regulations. FERC also sets the tariffs for investor-owned utilities. Hence, although Canadian utilities do not come under the direct jurisdiction of FERC, the requirement for an export permit to access US wholesale electricity markets establishes the requirement for Canadian utilities to meet FERC regulations. Thus, while Table 3 summarizes the policy changes that have taken place in the US, some of these changes apply to Canadian utilities that trade electricity with US utilities. In general, however, that the extent of regulatory change in Canada is less than the US, and comparatively recent.

Table 3: Major Orders and Regulations from the FERC for US Utilities (Joskow, 2005)

Date	**Description of Regulatory Change**
1935	Federal Energy Regulatory Commission (FERC) created to set prices for inter-state transmission service; no jurisdiction over state-owned utilities and
1960's	Development of Reliability Organizations (NERC) to set performance and safety standards for transmission systems
1978	Public Utility Regulatory Policy Act – provides a means for independent power producers (generators) to enter into electricity market,
1992	Energy Policy Act – removed ownership restrictions for utilities and non-utilities related to generation facilities
1999	Orders 888 and 889 – passed by FERC to provide Open Access to the transmission system, to support a competitive wholesale market for electricity
2000	Order 2000 – FERC's rule-based incentives for the creation of Regional Transmission Organizations (RTO's) to solve transmission issues, as well as providing incentives for jurisdictions to create Independent System Operators (ISO's) for transmission system planning and operation
2002	Standard Market Design (SMD) – Provided a standard design for the transmission and electricity markets. Strongly opposed by states and incumbent utilities.
2003	Wholesale Market Reform White Paper – FERC issues clarifications and cites the SMD as "guidance" for the implementing Order 2000.
2005	FERC issues further clarification on private and transmission issues, supports the review of national electricity corridors to relieve transmission congestion
2005	FERC provided with greater authority for identification, review, and approval of transmission corridors that are in the US national interest

2.2.1.2 National Environment Protection Act (NEPA)

In terms of environmental aspects, the Department of Energy looks for an appropriate agency to take the lead for managing the Environmental Assessment review. This agency could be an incumbent utility, or a federal agency that regularly reviews projects (such as the US Army Corps of Engineers). The lead agency is responsible for ensuring the Environmental Assessment is carried out in accordance with legislated requirements and that the project meets the requirements for mitigation of environmental impacts.

2.2.1.3 National Energy Board (NEB)

In Canada, the National Energy Board regulates transmission lines that cross the international border into the United States. It is important to note the NEB does not set tariffs for energy infrastructure, but relies on the presence of contracts following an open season to demonstrate the proposed project will be 'used and useful'[9]. The NEB also coordinates the Environmental Assessment of proposed projects with Federal and Provincial agencies. The NEB typically does not rely on detailed financial or technical information, but instead encourages proponents to comply with established recognized technical standards or provide specific commitments to meet objective and measurable criteria during the construction and operation of the facilities. The NEB is an agency of the Canadian federal government and has the legislated authority to make binding rulings on energy matters.

The NEB interest and expectations around electrical transmission lines have changed over the past three years. The NEB regularly compiles information regarding energy markets and trading (NEB, 2005) and has recently starting reviewing issues of transmission reliability across Canada. In fact, a report on electrical transmission systems reviewed the factors affecting reliability and concluded that the frameworks associated with electrical reliability are "diverse and evolving", and that interconnections between systems can significantly improve reliability, allowing adjacent utility networks to share reserves and improve market performance (NEB, 2004).

[9] An open season is an auction for services on a transmission line or pipeline. The intent is to offer the service in an open manner to all market participants, to establish fair market access. Bids for the open season, and the conclusion of the open season with contracts for service, are an important means to demonstrate the market need for a proposed transmission line or pipeline.

2.2.1.4 Canadian Environmental Assessment Agency (CEAA)

Environmental aspects of proposed transmission line projects are reviewed as part of the CEAA process. This process is carried out as part of the application for a Certificate of Public Convenience and Necessity from the NEB, providing greater efficiency in relation to permitting for transmission lines and other infrastructure projects. The CEAA process involves reviewing both the technical environmental impacts and the socio-economic impacts of the project.

2.2.2 Provincial/State Reviews and Approvals

2.2.2.1 British Columbia Utilities Commission (BCUC)

The BCUC regulates the activities of utilities within British Columbia. The Commission is a regulatory agency of the BC Provincial Government and administers the Utilities Commission Act. The responsibility of the Commission is to approve projects and utility operations that provide "safe, reliable, and non-discriminatory" energy services and set "fair" rates for utilities such that shareholders receive a "fair return". The Commission also has the responsibility to ensure that the competitive interests of BC businesses are not frustrated. As with the National Energy Board, the BCUC is a quasi-judicial body that has the legislated authority to make binding rulings. The BCUC also regulates intra-provincial pipelines and other utilities (BCUC, 2006a).

The Environmental Assessment Office (EAO) coordinates the environmental assessment of major projects in BC. This often occurs following the review and approval by the BCUC for a Certificate of Public Convenience and Necessity. The BC EAO monitors consultation carried out for a project, including consultation with First Nations. The Environmental Assessment Office will coordinate a review under the Canadian Environmental Assessment Act for provincial projects; however, it is not involved for approvals that are the jurisdiction of the NEB.

2.2.2.2 State Environmental Protection Assessment (SEPA)

The environmental permitting for compliance with state regulations is carried out under the SEPA process. As with the NEPA process, a local agency with direct involvement with local permitting issues has the option of taking on the responsibilities for the SEPA process.

2.2.3 Local Reviews and Approvals

2.2.3.1 Municipalities and Local Governments

Municipal authorities have jurisdiction over public rights-of-way within their jurisdictions, as well as specific powers relating to building development. In terms of transmission line development, municipal authorities have jurisdiction over any zoning that is required for project lands, as well as bylaws that must be met in terms of construction activities (noise and disturbance from construction activities, traffic management, protection of existing underground utilities, etc). Some municipal authorities also have bylaws relating to protection of specific trees or ecosystems, such as the Garry Oak trees and ecosystems in Victoria.

2.2.4 Summary

Regulatory frameworks for electrical transmission projects include issues important to national, regional, provincial/state, and local interests. Accordingly, permitting must address these issues, and the permitting framework can be a significant aid or hindrance to development. For example, the permitting carried out by the National Energy Board contains provisions for exemptions from provincial and local permitting requirements, to eliminate the need for independent reviews. Alternatively, the permitting for local and provincial/state requirements can be carried out separately (such as for the NEPA/SEPA process), with perhaps a longer delay in the process. The extent to which regulatory policies change and the reaction of permitting agencies to changes in policies can increase the uncertainty related to project development.

2.3 Market and Industry Analysis

Since transmission can significantly affect the cost structure of wholesale electricity markets, it is important to consider changes to the transmission system on a regional basis. In the Pacific Northwest, the Canada-Northwest-California report (NTAC, 2006) discusses a number of transmission options to improve the transmission capacity between Alberta and British Columbia to the Pacific Northwest. Currently, there are no transmission interconnections between Alberta and the US. However, the MATL (Montana-Alberta Tie Line) is under development to provide approximately 600MW of transmission capacity. Until this line is constructed, companies in Alberta looking to sell electricity into the US must use the BC transmission system. The Northern Lights Project, proposed to link Fort MacMurray with the Pacific Northwest (Montana to as far as California). This project could eliminate the need for Alberta electricity producers to use the BC transmission system to reach US markets. As a consequence, BC Hydro will have less Alberta thermal generation available for purchase at low prices in off-peak hours for later arbitrage (ZE PowerGroup, 2005).

Improvements in the transmission system are also underway in Washington, Oregon, and Idaho. Bonneville Power Authority (BPA) is developing over 770 miles of high voltage transmission lines, and has the largest single program for transmission development in the US (Pease, 2006). These new projects will add to BPA's existing network of 18,000 miles of transmission lines. The intent of these projects is to eliminate bottlenecks or "cutplanes" on the BPA transmission system. However, this expansion may end soon as BPA announced recently that no new generation would be available, and that customers should look at securing power contracts independently (BPA, 2006b). This policy would likely reduce the need for new transmission.

In regional terms, the market for transmission development in the Pacific Northwest is heavily influenced by both environmental and cost factors as well as the existing transmission constraints. For example, the seasonal water levels in reservoirs and the price of natural gas are important determinants of the local demand for electricity in California and the Pacific Northwest. This demand heavily influences the price differential between BC and the competitive markets in Washington/Oregon, and California. When BPA reservoir water levels are low, and gas prices are high, the price differential is pronounced whereas when either water levels are high, or gas prices are low, the price differential is softened. The result of these market forces is the sharp rise in electricity costs to BC ratepayers if BC Hydro is forced to import to meet provincial load requirements during low water years (NEB, 2005). The existing transmission constraints throughout the Pacific Northwest also contribute to this price differential, in that local markets can be inhibited from reacting to price signals in other parts of the region (DOE, 2006).

Figure 4 illustrates the factors affecting the industry for private transmission development. These include: the rivalry of existing private development competitors; the threat of new competitors entering into the industry; the threat of substitutes eliminating the need for private transmission projects; the bargaining power of suppliers, consultants, and government agencies; as well as the bargaining power of customers, often incumbent utilities. A broad review of the factors affecting the transmission development industry provides some insights into the evaluation of transmission project alternatives.

2.3.1 Rivalry among Competitors

The rivalry among competitors for private transmission development is high. Within the private transmission development industry, there are relatively few firms which include: Boundless Energy, the developers of the Neptune Project (and joint venture partners with Sea

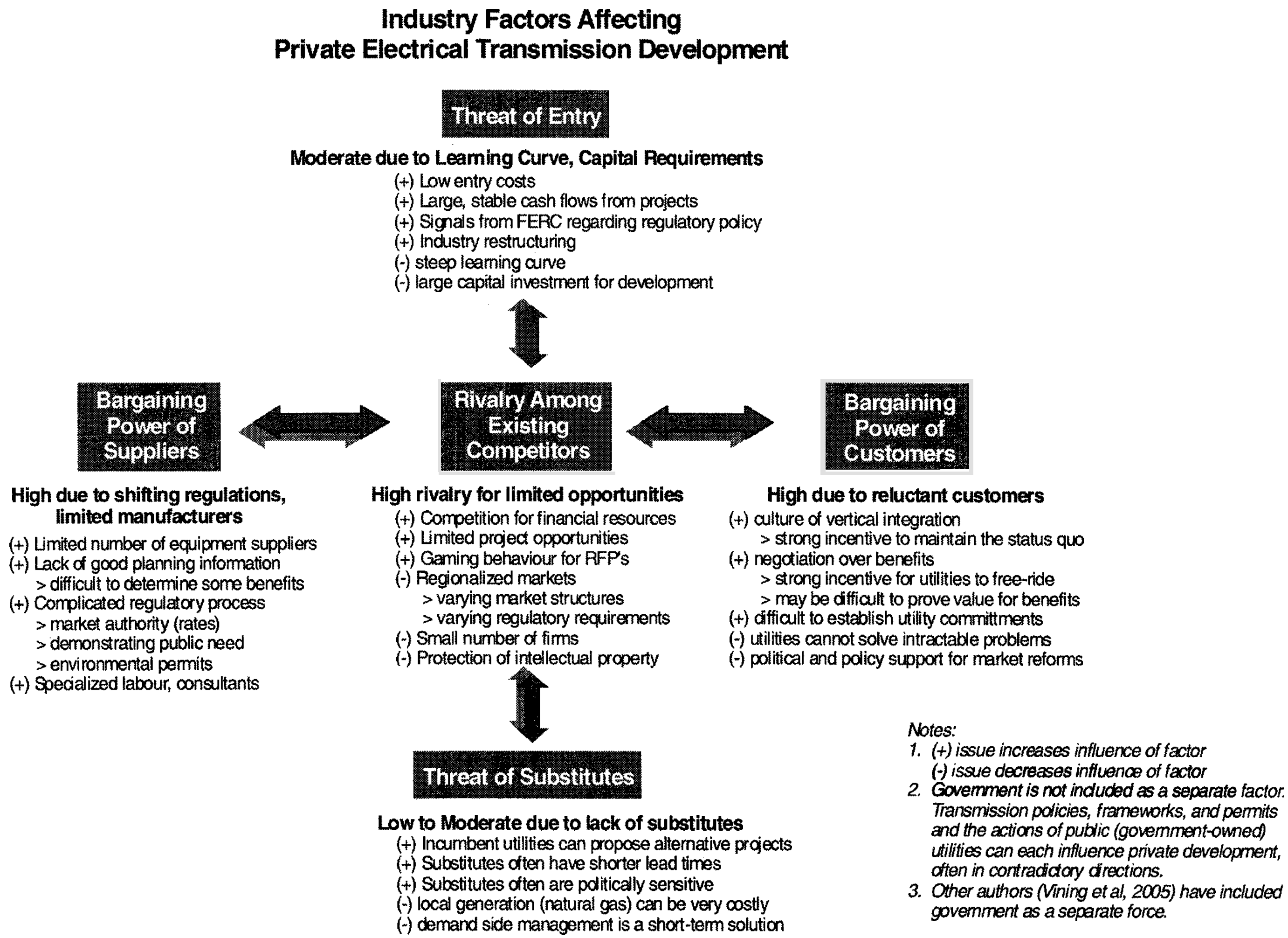


Figure 4: Five Forces Analysis for Electrical Transmission Development (after Bukszar, 2006)

Breeze on the Juan de Fuca Cable and Vancouver Island Cable Projects); and TransEnergie, a subsidiary of Hydro Quebec, developer of the Cross-Sound Cable in New Jersey. TransElect, another company, has developed private transmission projects in the western US and Australia. Other private companies may include project development only as one small part of their transmission operations, such as ITC Transmission in Michigan.

Important factors that increase the rivalry among merchant transmission line developers relate largely to the competition opportunities and resources. There are a limited number of specialized investment firms that provide equity funding for private energy development projects; Krellenstein (2004) lists seven firms that are likely candidates.

Considerable financial resources are required to develop a concept from inception. For example, the Juan de Fuca Project currently under permitting and preliminary engineering by Sea Breeze Pacific has a Development Loan Agreement in place for $8 million, which does not include detailed design or construction permitting (Sea Breeze, 2005c).

Also, as pointed out in Section 2.1.1, the opportunities for developing merchant projects from inception are rare, as they are a small subset of total interconnections between incumbent utility systems. There may be significantly more opportunities to work with utilities on P3 projects, and these projects may not have the significant development funding requirements as the incumbent utility may decide to provide some capital for development. For public transmission, the competition between private development firms during an RFP process for P3 projects could significantly erode the potential profit for projects.

It is also important to note that incumbent utilities can also be competitors. For example, private transmission projects may disrupt the cost structure of electricity markets prompting incumbent utilities or local politicians to oppose the project. In the case of Cross-Sound cable, the attorney general in Connecticut was opposed to the construction of the project and blocked its operation once the project was complete (Randell and McDermott, 2003). The Department of Energy ordered the line into operation if specific market conditions were met. However, the line remained idle until the August 2003 blackout, when the Department of Energy ordered the line operational on an emergency basis. In BC, either the VIC Project or the JDF Project could postpone or eliminate the need for the VITR Project, and this possibility was explored by the BCUC in its review of the VITR Project (BCUC, 2005a, 2006b).

Rivalry among merchant developers is softened through the small number of firms, the highly regionalized nature of the projects, and the lumpy nature of the investments. Given the relatively large number of prospects for transmission projects (including P3's), and the relatively small number of firms that are spread throughout North America, rivalry among competitors often does not overlap. Also, the regional nature of the transmission development industry due to the differing regulatory environments, wholesale market structures, and incumbent utility practices all reduce rivalry since successful development strategies and relationships with key agency personnel typically do not translate to other regions. The lumpy nature of the investments also eliminates the rivalry among competitors at the project level, where the development of one project provides a first-mover advantage that often precludes the development of related opportunities (Joskow and Tirole, 2005).

2.3.2 Threats due to New Entrants

Despite the sizeable cash flows and low entry costs, the threat of new entrants to the private electrical transmission development industry is only moderate. Even though the rates of return can be lower than for other types of investments, the widely recognized need for additional transmission infrastructure have caught the interest of both developers and financiers (Roseman and DeMartini, 2003). The financial returns from non-regulated projects can range from 11 percent to as much as 13.5 percent, whereas regulated rates of return are lower, perhaps slightly over 9 percent , with a corresponding lower risk in development (BCUC, 2006b). The low entry costs are a function of the small organization needed for development. In fact, the Sea Breeze team developing the Juan de Fuca Project is less than 10 staff, working with a series of specialist consultants.

Despite the tempting returns on completed projects, considerable entry barriers exist. These include learning curves, interconnection regulations, and financing. Even though the project team may be small to start development of a project, it is essential to have personnel with the suitable expertise and experience. Such skills and experience are uncommon, as much of the knowledge for transmission development resides within utilities. Further, permitting requires a multi-disciplinary effort with considerable flexibility to coordinate specialists for efficiency and efficacy. For those without the skills and expertise, securing financing can be difficult without a proven track record.

Interconnection regulations and financing requirements also deter for new entrants. Under FERC regulations, new entrants must respect the interconnection queue position of existing merchant developers; specifically, once an interconnection application is received it is not possible for other developers to attempt a competing project. The uncertainties around project development can be considerable for most financing companies, as inexperienced project development can lead to considerable delays in permitting and project completion, as well as potential liabilities for liquidated damages.

2.3.3 Threats from Substitutes

The potential for other projects to substitute for private transmission projects is low to moderate. Substitutes for electrical transmission lines generally consist of new generation facilities that are located close to the customer load areas, or demand-side management to reduce the amount of electricity consumed. New generation often consists of natural gas turbines, since these can be often be situated very near the load centres and reduce the need for transmission. For demand-side management, conservation can contribute significantly to savings. In fact, BC Hydro expects to obtain a 30 percent decrease in demand with its PowerSmart Program (BC Ministry of Energy, 2005). The potential for demand side management is also under consideration as part of the future supply planning in BC (BC Hydro, 2006a). Note that either of these alternatives can be implemented in a relatively short time frame, increasing the appeal of the substitutes to incumbent utilities.

Compared to network expansions of the electrical transmission system, these substitutes have some serious shortcomings. Given the sharp rise in the price of natural gas, the net present value (NPV) of operating these types of facilities can exceed the cost of transmission expansion. Demand-side management and conservation programs do not address medium- and long-term increases in demand and act as a considerable disincentive for economic activity in a region, and the actual savings may be much less than expected (Loughran and Kulick, 2006). Note that either of these alternatives can be implemented in a relatively short time frame, increasing the appeal of the substitutes to the incumbent utilities.

Transmission line projects proposed by incumbent utilities can substitute for projects that are under development by private companies. In this manner, private companies must compete on technical, financial, and regulatory terms with incumbent utilities. Given that incumbent utilities may have suitable expertise for transmission project development, and that they are often able to easily finance the early development stage of projects, any transmission projects imposed by incumbent utilities could substitute for projects proposed by private developers[10].

[10] Generally, the interconnection rights contained in the transmission operating requirements that conform to FERC Order 2003-A are such that applications for interconnection to a transmission system form a "queue" in which the incumbent utility must study proposed projects on a sequential basis.

2.3.4 Bargaining Power of Suppliers

The bargaining power of suppliers is high due to shifting regulations and the limited expertise and manufacturers. Suppliers for private transmission developers include manufacturers that supply the materials and equipment, specialized labour for project development, incumbent utilities that provide information for project analysis, and regulatory agencies that provide approvals for project development.

There are less than five major companies that manufacture cables and specialized equipment for transmission projects (Sea Breeze, 2006a). This limited number can be a significant concern for specific types of activities, such as the supply, manufacture, and installation of marine transmission cables where very few suitable ships exist. In the case of a project with very tight timelines for completion, the relatively few firms available with design expertise as well as manufacturing and installation capabilities can be a significant obstacle to meeting the target in-service date. In addition, much of the environmental studies for permitting must be carried out by consultants with local and highly specialized expertise and experience. Due to their scarcity, both manufacturers and specialist consultants are able to extract considerable rents during project development.

The incumbent utilities and local regulators also have significant influence as suppliers for merchant transmission projects. Accurate information is needed early in the development process to establish whether a project is technically and financially viable; however, this information (if it exists) is held by the incumbent utility and may not be accurately reported (EIA, 2004). Also, the local regulators and the government agencies can set the acceptance thresholds high for projects such that it is difficult to establish authorizations with certainty. For example, the State Agencies exercised authority following earlier approvals of the Cross-Sound Cable to keep the facility from operating until the August 2003 blackout (Randell and

McDermott, 2004). The issue around regulatory approvals is compounded by overlapping federal and state/provincial jurisdiction for many project approvals.

Obtaining permits to demonstrate "public need and necessity" can be particularly problematic for private developers. In BC, recent regulatory hearings involving a BCTC project and a Sea Breeze project showed the test for demonstrating the public need was very high, (BCUC, 2006c). For private developments that include a partnership with utilities, the utility and developer work together and demonstrate the need with likely less effort. Even for an independent merchant facility, the incumbent utilities may still have to meet the "public need and necessity" test and environmental thresholds before being able to contract for use of the facility (BCUC, 2006b). As a result, the approvals of regulatory authorities are a critical factor in the development of any private project.

2.3.5 Bargaining Power of Customers

The bargaining power of customers is high due to the potential for reluctant customers to affect the development of transmission projects. Incumbent utilities are typically the customers of merchant facilities, and they may have a strong culture of vertical integration and an incentive to maintain the *status quo*. One possible reason for this is the cost structure for the operations, established based on regulated consumer rates and thus static revenues that could be disrupted by merchant transmission projects.

It can also be very difficult for a private developer to negotiate benefits and reach agreements with incumbent utilities (EIA, 2004). These difficulties arise from accurately measuring congestion costs in some markets or the deferred project costs (Lesieutre and Eto, 2003). Specifically, the congestion costs can only be calculated if a considerable amount of information is known about the wholesale trading market (transactions not completed, generator costs compared to market costs, effect of redispatch payments, political incentives for generators not reflected in price). This information is complicated by loop flow in alternating current systems, which is not controlled and thus no direct measurement of transmission is practical. Accordingly, there is a strong incentive for incumbent utilities to free-ride on the merchant facility, such that they undervalue the benefits, lower the potential revenues, and effectively reduce the negotiating power of the private developer (Joskow and Tirole, 2005). The incentive to free-ride creates a Nash equilibrium between the adjacent utilities, with each only willing to pay for the marginal cost of service on an as-needed basis rather than for other benefits (which could justify the construction costs). As discussed in Section 2.3.4 above, the regulatory agencies can also favour the incumbent utility in mediation or arbitration, leading to significant and time-consuming costs to conclude agreements.

Lastly, and perhaps most importantly, there is an over-arching push for more innovation and market incentives to encourage private investment into the sector, which reduces the power of incumbent utilities. For example, following the FERC approval of the Juan de Fuca Market Proposal by Sea Breeze (FERC 2005a), the FERC revisited its pricing and market reforms for transmission (FERC, 2005b). Specifically, FERC highlighted incentives for: a rate of return sufficient to attract new investment; cost recovery for prudent costs during development; new tax and depreciation rates to increase early cash flows for transmission projects; and flexible ownership structures to promote private investment in transmission capacity projects. Incentives were also put forward for public utilities that join regional transmission organizations, as a means to establish effective working groups to solve transmission issues on a regional basis[11].

[11] Regional Transmission Organizations (RTO's) are used in many areas of the eastern US to discuss, investigate, analyze, and implement regional solutions to transmission capacity and reliability. GridWest, an RTO for the western US and Canada, failed when BPA pulled out. BPA has since started ColumbiaGrid and is proposing this as a regional organization (ZE PowerGroup, 2005).

2.4 Industry Attractiveness

2.4.1 Present Attractiveness

The transmission industry has significant appeal for private companies. It represents an opportunity to earn sizeable, stable returns for projects with relatively low entry costs. Private firms currently developing transmission projects have considerable advantages over new entrants, particularly due to interconnection rights and site location selection that can provide first-mover advantages, and the learning curve for project teams with the expertise to navigate the very complex set of technical studies and regulatory requirements for permitting. Electrical transmission projects also have multiple revenue streams, based both on tolls for transmission through the project as well as other reliability and ancillary benefits.

The realities that must be confronted by merchant developers result from the market power of incumbent utilities and the level of collaboration that is required to complete project development. In Figure 4, the Five Forces Analysis shows that incumbent utilities appear in each box: they can be rivals for the development of projects in a specific area; they can enter the merchant transmission business, as Quebec Hydro has done with TransEnergie; they can be suppliers of very important information for the early stage evaluation of projects or project approvals; and they can choose to implement substitutes for merchant project development.

The approvals from regulatory agencies also significantly affect the merchant transmission industry. It is ironic that incentives for US merchant transmission which are intended, at a policy level, to efficiently develop the overall system would meet with resistance from local regulatory agencies and incumbent utilities. The culture of vertical integration and locational market power appears to have considerable inertia, such that merchant transmission projects must be superior in technical, financial, and political terms before gaining widespread support.

2.4.2 Future Trends

The favourable appeal of the electrical transmission industry for private developers is likely to continue. Given the recent Orders of FERC and the recent publications by the US Department of Energy, a marked increase in transmission infrastructure is quickly needed. The move toward designation of national energy corridors to increase electricity trade throughout North America (DOE, 2006) and the increased focus on electrical reliability following the August 2003 blackout provide rationales for transmission expansion and the formation of Regional Transmission Organizations. Such organizations consider an integrated view of how to improve the transmission system to meet the expected regional demands. As incumbent utilities participate in such organizations, projects can be conceived and developed with merchant companies under public-private partnerships. It is likely that merchant development will continue be necessary for intractable problems where incumbent utilities can not or will not agree on a solution. The innovation and risk-taking approaches of merchant developers are an essential complement to the resources of the utilities for the timely and efficient expansion of the transmission system in North America.

2.5 Key Success Factors

Based on the factors in the industry analysis and the attractiveness of the private transmission industry in the present and future, several key success factors are evident. These are: 1) identifying private transmission development opportunities, particularly considering both local and regional needs; 2) understanding suitable technologies and their associated costs and benefits; 3) pursuing opportunities through competition or collaboration; and 4) adapting to changing regulatory policies and permitting requirements.

Given the relatively few opportunities for true merchant projects, identifying such opportunities is crucial to the first step in early project development, and a key factor in succeeding against existing private competitors. The rapid identification and investigation of such opportunities is crucial to the success of private transmission development. Given the resources that are required to develop projects, and pace of regulatory change, it is important for a private development company to identify projects that address both local and regional needs, as a means to garner support in the early stages of permitting and development.

Understanding suitable technologies is necessary to develop projects that are innovative and cost effective. This knowledge can provide a competitive advantage relative to rival firms. Since the feasibility of a project depends on the financial and regulatory requirements, the experience from previous projects is invaluable for future development. An incomplete understanding of newer technologies, and in particular their costs and benefits, is a key barrier to firms attempting to develop transmission projects.

The flexibility for a private transmission company to either compete or collaborate, depending on the situation, is another key aspect of success. Given the relatively few opportunities for true merchant projects, a company that can be flexible in its approach to project development and either develop projects from inception or collaborate on projects with utilities has the ability to compete on multiple levels and at various locations. The result of such flexibility is a private firm following a loose bricks strategy, where it takes on different types of roles and projects depending on the situation, and the flexibility afforded by this strategy is a means to decrease the bargaining power of suppliers and customers.

Adapting to the regulatory requirements of various jurisdictions and the changes in regulatory policies and requirements is also a key success factor. The regulatory policies, and thus the permitting requirements, are evolving such that the knowledge of the current and likely future requirements is essential for successful development. Adapting to the changing regulatory environment is a key means to shorten the permitting timeline and thus decrease the threat of substitutes, either by others or incumbent utilities.

From the four key success factors above, the most important is for a private transmission company to be flexible. Flexible approaches also allow for a greater consideration of project opportunities, leading to a loose bricks approach to project development. Given that the development of projects is often a race against time to obtain the permits for a project, flexibility can also assist with understanding and reacting to a changing regulatory environment. A culture of flexibility also fosters an interest in, and adoption of, newer technologies for project development that are often fundamental in solving existing transmission capacity and constraint problems and thus provide a competitive advantage.

In terms of flexibility, two organizational aspects are particularly important. The first is the size of the firm, as smaller firms can utilize informal networks of knowledge transfer and quickly adapt to new information. The second aspect is the ability to integrate this knowledge and effectively implement tactics for permitting and project development. Thus, the capabilities of the private company require a small, flexible staff with very diverse expertise that can quickly and effectively make critical decisions. Such expertise must also be complemented by considerable experience, given the amount of soft skills such as relationship development, negotiation, and knowledge transfer that are required for success.

3 DESCRIPTIONS OF ALTERNATIVES

This chapter describes the three project alternatives for transmission lines to meet the required expected shortfall in electricity supply for Vancouver Island. Each project has specific characteristics in terms of technology, location and route, financial viability, regulatory requirements, and development timelines. Figure 5 shows the general locations of the project alternatives.

3.1 Vancouver Island Transmission Reinforcement Project (VITR)

The Vancouver Island Reinforcement Project is a proposal by the British Columbia Transmission Corporation (BCTC) to connect the Lower Mainland with Vancouver Island. Studies started in spring 2005, with operation scheduled to meet the shortfall in demand by winter 2008 (BCTC, 2005a).

The BCTC is a Crown Corporation that was created in 2003 as part of the Province's restructuring of the electricity industry. Although BCTC would develop and operate the VITR Project, the asset would be owned by BC Hydro. Some major components of the project, such as the marine cables, would be developed as an EPC[12] contract, whereas other components of the project would be designed and constructed separately (BCTC, 2005a).

[12] An EPC Contract is a single contract that encompasses engineering, procurement, and construction. In the case of a marine transmission cable, the EPC contract would include the design of the cable to meet power transmission specifications; manufacturing (or purchase) of the cable; delivery; and installation.

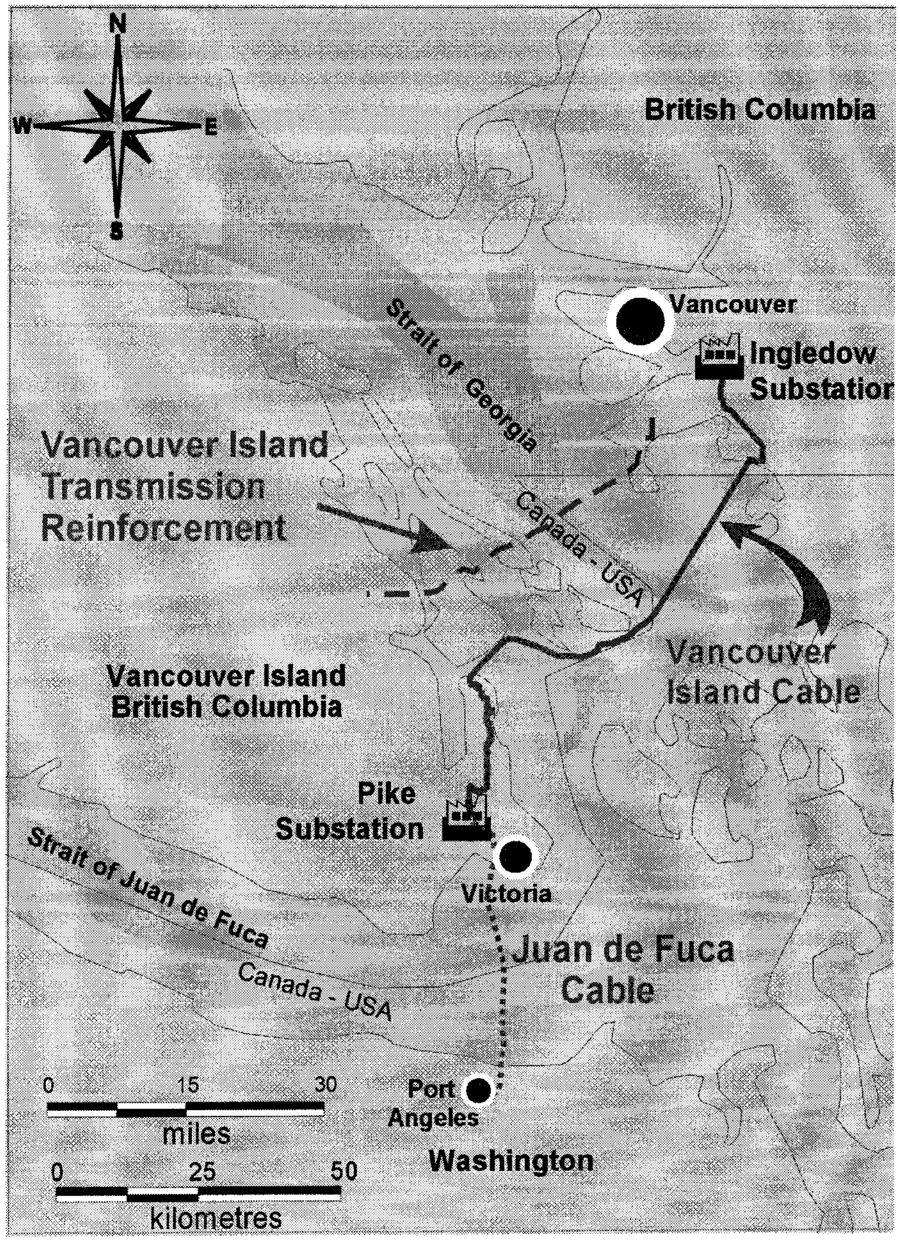


Figure 5: Routes for transmission line alternatives (adapted from Sea Breeze, 2005a and Sea Breeze, 2005b with permission).

3.1.1 Project Technology: Conventional HVAC

The Vancouver Island Transmission Reinforcement Project includes the use of conventional High Voltage Alternating Current (HVAC) technology, similar to almost all other transmission lines and substations in British Columbia. HVAC technology commonly utilizes overhead transmission on towers for terrestrial installations. This technology is well understood, with standard designs and contracts for construction.

3.1.2 Project Location and Route

The Vancouver Island Transmission Reinforcement Project would link two existing AC substations. The first, in central Delta, is in an area prone to instability (liquefaction) following earthquakes; the second substation is located near Duncan, some 50 km north of Victoria. For overland portions of the VITR route, BCTC plans to replace the existing transmission poles with a single pole structure. A short portion of the route is proposed for underground installation in Tswawwassen. The right-of-way width would not be reduced, and may be reserved for the next phase of transmission line development to Vancouver Island, tentatively slated for 2017[13] (BCTC, 2005b).

Table 4 shows the lengths of the terrestrial and marine portions of the project. Note that the terrestrial portions of the project pass through areas with existing residential development in the Lower Mainland (Delta and Tsawwassen) as well as rural areas on Galiano and Saltspring Islands. The marine portion of the route crosses the Strait of Georgia south of the existing BCFerries terminal facility, in a region of known submarine landslides[14]. The area on the east

[13] The demand for electricity on Vancouver Island is growing, and the second transmission line (VITR2) would be needed. This line would utilize the existing poles and terrestrial routes for VITR, but would require an additional marine cable (BCTC, 2005a).

[14] This area, known as the "Roberts Bank Failure Complex", had a 1,000,000 cubic metre landslide initiate in 1984 following heavy waves at high tide near the mouth of the Fraser River. Several landslide specialists have raised concerns about the existing cables and the potential to impact new cables if future landslides occur in this area (BCUC, 2006b)

side of Galiano Island has sharp bedrock ridges, a concern for existing submarine cables in the area.

Table 4: Specific Data for Vancouver Island Transmission Reinforcement Project.

	Marine	Terrestrial	
	Conventional HVAC Marine Cable	Aerial Conventional HVAC Cables	Underground HVAC
Length	Approximately 43km across the Straight of Georgia	Approximately 8.7km in the Lower Mainland Approximately 27km on the Gulf Islands and Vancouver Island	Approximately 3.7km in the Lower Mainland No underground lines on the Gulf Islands and Vancouver Island
Capacity	Approximately 600 MW	Approximately 600 MW	Approximately 600 MW
Type	±230 kV Cables	±230 kV Cables	±230 kV Cables
Converter Stations	No converter stations needed; additional upgrades within existing substations		

3.1.3 Project Financing Considerations

As part of the requirements for the Certificate of Public Convenience and Necessity, BCTC determined the overall costs for the project. The estimated the capital cost of the VITR Project was $252.6 million, with the project definition costs estimated as $8.4 million of this cost (Table 5). As the owner of the transmission assets in the province, BC Hydro would fund the development of the VITR Project. Chapter 5 contains a additional discussion regarding the financing of the project.

Of particular note in this table is the total for indirect costs. This is the total for benefits that are provided by either of the VIC or JDF projects, such as avoiding the seismic upgrading for the Arnott Substation in Delta, the replacement of substation equipment on Vancouver Island, and other benefits that are provided by the controllable aspects of having an HVDC Light® system and its controllable converter stations link the Lower Mainland with Vancouver Island. These benefits are discussed thoroughly in Chapter 5, along with the uncertainty around each of the items.

Table 5: Financing summary for VITR Project (BCTC, 2005)

VITR Costs and Benefits	Estimated Cost[1]
Direct Costs	($ millions)
Project Definition	23.7
Project Implementation	215.7
Contingency	19.0
Operations and Maintenance	2.6
TOTAL COSTS	**252.5**

Notes:

1. All costs in 2005 dollars, assuming a discount rate of 6%.

2. Project Definition includes $8.4 million in sunk costs (2006 dollars).

3.1.4 British Columbia Utilities Commission - Regulatory Application

The Vancouver Island Transmission Reinforcement Project was put forward by BCTC in an application to the BCUC in July, 2005. The application contained technical feasibility studies, as well as financial analyses to evaluate the estimated capital costs of the project.

The proposal for the Vancouver Island Reinforcement Project met with considerable public and special interest opposition, with a total of 11 groups intervening. Groups opposing the project included: the Corporation of Delta, concerned about impacts to municipal infrastructure residents along the transmission corridor; and citizen groups in Tswawwassen and the Gulf Islands, concerned about the health effects of EMF and the decrease in property values. Groups also intervened to represent commercial energy users and industrial ratepayers, with concerns about the financial aspects of the VITR Project. BC Hydro also intervened in the proceeding, to represent the residential customers on Vancouver Island (BCUC, 2006c).

Sea Breeze Pacific, a private company developing transmission projects, intervened as a means to propose project alternatives, specifically the Vancouver Island Cable Project (Sea Breeze, 2005a) and the Juan de Fuca Cable Project (Sea Breeze, 2005b).

3.1.5 Timeline for Development

The timeline for developing the Vancouver Island Reinforcement Project is shown in Figure 6. Based on original information provided by BCTC, the project would be in service in time to meet the peak demand for winter 2008. Note that although the project starts and ends in BC, it passes through US waters west of Point Roberts and requires approvals from US agencies (BCTC, 2005a). The timelines are also short for some activities on the project, particularly related to property acquisition (contained within the Environmental Permitting task). An analysis of the timelines for the VITR Project is contained in Section 4.2.4.2.

3.2 Vancouver Island Cable Project (VIC)

The Vancouver Island Cable (VIC) Project alternative was developed by Sea Breeze during the BCUC review of the VITR Project (Sea Breeze, 2005a), August and September of 2005[15], to meet the deadline imposed by BCUC. The Commission consolidated the review of the applications as a means to directly compare the two applications on November 19, 2005 (BCUC, 2006b).

Sea Breeze Pacific is a joint venture between two companies, Sea Breeze Power Corp of Vancouver, B.C. and Boundless Energy of York Harbour, Maine. Sea Breeze Power Corp recently permitted a large wind farm on northern Vancouver Island. Boundless Energy recently completed the development of a large underwater transmission line to link New Jersey with Long Island in New York, a project that is currently in construction.

[15] This tight timeline was imposed by the BCUC to reduce, to the extent practical, the total time for the review of the project alternatives.

Task Name	Start	Finish
Concept Development	1/19/04	5/28/04
Feasibility Studies	7/1/04	11/26/04
Preliminary Engineering	4/19/04	5/6/05
CPCN Permitting	11/4/04	2/17/06
Environmental Permitting	8/2/04	10/20/06
Planning, Budgeting	4/4/05	5/27/05
EPC Contract	10/4/05	4/26/07
Detailed Engineering	8/1/05	6/5/08
Construction	4/6/06	10/3/08
Commerical Operation Date		10/31/08

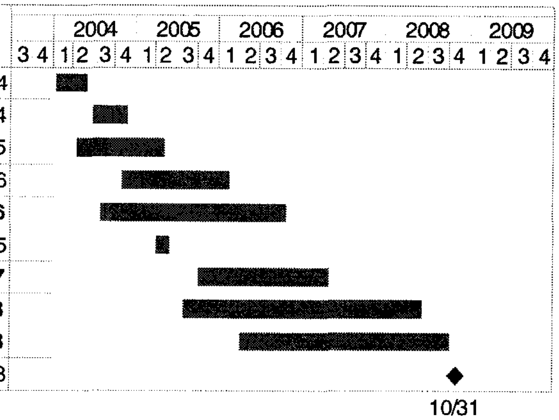


Figure 6: Timeline for the Vancouver Island Transmission Reinforcement Project

3.2.1 Proposed Technology: HVDC Light®

High Voltage Direct Current (HVDC) technology has been used for decades for bulk transmission systems. HVDC Light®, developed exclusively by ABB Inc. of Sweden, represents a refinement on this transmission technology with the use of newer technology for cables and converter stations (required to convert AC electricity to DC for transmission, and vice versa). ABB is a multi-national company which designs, manufactures, and installs high voltage electrical transmission systems throughout the world. ABB (2005) contains a technical description of the HVDC Light® technology along with its associated benefits relative to conventional AC transmission systems. Early in the concept development of the Juan de Fuca Project, Sea Breeze engaged ABB to provide some information and technical support. This working relationship continued through the development of the VIC Project proposal.

The cables for HVDC Light® are relatively small and light, and consist of a solid core, with no oils or coolants to leak in the event of a cable break of excessive deterioration. Moreover, the cables are designed to be buried underground, both in the terrestrial and marine environments, in close proximity. As a result, since the cables are buried as a pair in close proximity (less than 0.5m), the magnetic fields from the cables largely cancel out, and the residual field is mostly less than the earth's natural magnetic field[16]. This cancellation effect provides for greater acceptance by regulatory agencies and the public in terms of health and environmental impacts (ABB, 2005, Greenpeace, 2005). In addition, the narrow width of the cable footprint allows for more engineering options in terms of potential routes and alignments in crowded corridors (Jacobson et al, 2005).

The converter stations for HVDC Light® systems present significant improvements over older converter stations and existing AC substations (ABB, 2005). These improvements are the result of the proprietary technology developed around the voltage source converters, which allows for extremely fast switching and controllable power delivered to the AC system (ABB, 2005). Reactive power can be supplied by the converter stations, providing stability to the AC system to maintain the system frequency within the required operating limits and thus eliminating the need for additional equipment on the transmission system. This extremely fast switching also allows for 'blackstart' capability, so the HVDC Light® link can prevent cascading blackouts and significantly decrease the amount of time required to restart the AC (ABB, 2005). As discussed by Jacobsen et al (2005), the smaller size of the converter stations also facilitates easier permitting and land acquisition in city areas.

There are approximately six HVDC Light® projects currently in operation, with approximately another seven currently in development. The controllable nature of HVDC Light® allows for up to 770MW[17] of transmission over long distances, through ecologically sensitive areas due to the significantly lesser impacts, and the ability to link grids that are asynchronous (AC grids operating at differing frequencies). The controllability of the converter

[16] The one exception is directly over the buried cables, where the strength of the magnetic field can approach the strength of the earth's field, depending on the depth of burial and the spacing of the cables (Sea Breeze, 2005b).
[17] The size of HVDC Light® systems under development include systems up to 770MW. At this time, systems capable of 330MW transmission capacity, and the 540MW system planned for the VIC and JDF Projects would utilize the same technology and cables as the 330MW system, only a slightly different arrangement for voltage source converters (Sea Breeze, 2006a).

stations for HVDC Light® provides for ancillary benefits as well as the ability to precisely control the electrical flow on the cables and thus have a system that is capable of toll charges (ABB, 2005). In addition, there are dozens of older HVDC projects in operation worldwide, using older cable and converter station technology.

3.2.2 Project Location and Route

The concept for the VIC Project was to develop a proposal that would provide a solution to meet the identified need for Vancouver Island, considering the permitting timelines and engineering/technical issues facing the VITR Project.

The VIC Project route links a prominent substation on the Lower Mainland with the main substation in the Greater Victoria area (Figure 5). On the Lower Mainland, the project would connect to Ingledow Substation in central Surrey, which is the one of the most prominent and seismically secure substations in the Lower Mainland. On Vancouver Island, the VIC Project would connect to Pike Lake Substation, the main substation in the Greater Victoria area.

The terrestrial VIC route follows existing utility rights-of-way and municipal streets. In Surrey, the route follows the existing BC Hydro HVAC aerial transmission lines to south Surrey, and then under streets to White Rock. Horizontal directional drilling would be used to install the cable out into Semiahmoo Bay, for security cable protection and reduce the amount of time required for environmental permitting. On the Saanich Peninsula, horizontal directional drilling would also be used for similar reasons. The route would follow existing municipal streets and aerial transmission rights-of-way to the Pike Lake substation, some 10 km northwest of Victoria. Table 6 lists the estimated lengths for the project.

In the marine environment, the route would follow gently-sloping seabed areas from White Rock to the Boundary Pass area, near the Gulf Islands and then along the GSX corridor (previously investigated for a natural gas pipeline). Although it was never constructed, the technical studies carried out for the GSX pipeline would provide ample technical information to evaluate the marine conditions for installation of the HVDC Light® cables. Even though the VIC route is considerably longer than the VITR route, it represents fewer technical problems as it avoids areas of potential submarine landslides and uses a technology that allows for underground installation, and thus collaboration with municipalities[18].

Table 6: Specific Data for Vancouver Island Cable Project

	Marine	Terrestrial	
	HVDC Light®	HVDC Light®	HVAC
Length	Approximately 67km across the Straight of Georgia	Approximately 21km on the mainland and 32km on Vancouver Island	About 200m to as much as 1000m for each of two converter stations to link with substations
Capacity	574 MW rated	574 MW rated	> 574 MW rated
Type	±150 kV HVDC Light®	±150 kV HVDC Light®	3-phase AC
Converter Stations	150 m x 100 m (492.1' x 328.1') located near existing substations		

3.2.3 Project Financing Considerations

Since the VIC project started and ended in BC, it falls under the jurisdiction of the BCUC and tolls are not appropriate to generate revenue for the project. Rather, Sea Breeze proposed the VIC project as a facility that would be "leased" to BCTC for a yearly payment, and these revenues would offset the capital costs for construction. This would, in effect, result in a regulated rate of return for Sea Breeze as sponsors of the project since the BCUC would review and approve the "lease" payment.

[18] Municipalities very often have plans for road upgrades and utility improvements, or additional infrastructure such as bike paths and walking trails. The trenching work of the VIC and JDF Projects allows for some level of collaboration with the municipalities along the route, and garnered letters of (conditional) support from five of the seven municipalities along the VIC route.

In terms of the estimated costs, the converter stations and the longer cable route for the VIC result in a higher cost (not including contingency and operational costs) of $349.8 million, compared to the VITR Project (Table 7). Note that the benefits for the project are due to the controllable transmission link between Vancouver Island and the mainland, providing savings for additional equipment and system operation. Section 5.2 contains a discussion of the indirect benefits associated with the VIC project.

Table 7: Financing summary for the VIC Project (Sea Breeze, 2006)

VIC Costs and Benefits	Estimated Cost[1]
Direct Costs	($ millions)
Project Definition[2]	23.7
Project Implementation	326.1
Contingency	10.0
Operations and Maintenance	10.8
TOTAL COSTS	**370.6**

Notes:
1. *All costs in 2005 dollars, assuming a discount rate of 6%.*
2. *Project Definition costs include $1 million in sunk development costs.*

3.2.4 British Columbia Utilities Commission - Regulatory Application

The Certificate of Public Convenience and Necessity application for the VIC project involved was submitted to the BCUC on September 30, 2005. The rapid preparation time for this application was due to the earlier work that Sea Breeze had carried out on the Juan de Fuca Project, significantly reducing learning curve and using the JDF consulting and technical team to quickly carry out the feasibility studies.

3.2.5 Timeline for Development

The timeline for the development for the VIC Project is shown in Figure 7. Note that the development is shorter through the EPC contract relationship with ABB as well as route selection which avoids problematic areas.

Task Name	Start	Finish
Concept Development	8/5/05	8/15/05
Feasibility Studies	8/15/05	9/30/05
Preliminary Engineering	8/15/05	9/30/05
CPCN Permitting	8/30/05	2/17/06
Environmental Permitting	9/5/05	12/12/06
Planning, Budgeting	12/27/05	5/9/06
Detailed Engineering	5/9/06	9/14/07
Construction	11/13/06	1/18/08
Commerical Operation Date	1/21/08	1/21/08

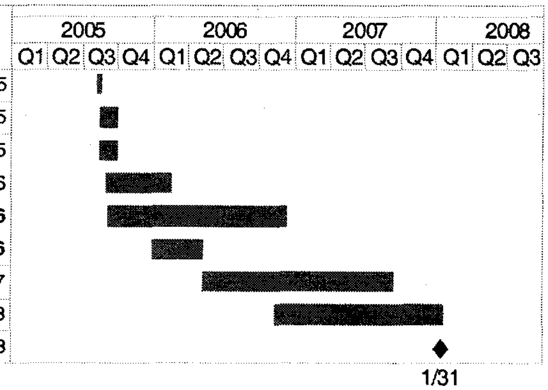


Figure 7: Timeline for development of the Vancouver Island Cable Project

3.3 Juan de Fuca Project (JDF)

The Juan de Fuca Cable (JDF) Project was proposed by Sea Breeze Pacific, a joint venture between Sea Breeze Power Corp of Vancouver, B.C. and Boundless Energy, LLP of York Harbour, Maine. The project started development in fall of 2004 prior to the VIC Project. Environmental and engineering studies were carried out throughout 2004 and into early 2006 (Sea Breeze, 2005b).

The purpose of the Juan de Fuca Project is twofold. The first relates to the increase the electricity trade between BC and Washington, and the second involves fulfilling the need for additional transmission to Vancouver Island. As a transmission line project that would interconnect Canadian and US endpoints, the project falls under the regulatory jurisdiction of the National Energy Board.

3.3.1 Proposed Technology: HVDC Light®

The JDF Project utilizes HVDC Light® technology for electrical transmission that is well suited to the need to link the two asynchronous AC transmission systems of BCTC and BPA. The HVDC Light® system is the same as proposed for the VIC project, allowing for timely approvals due to the lesser environmental impacts.

3.3.2 Project Location and Route

The JDF Project would link an existing BC Hydro substation in Greater Victoria with an existing AC substation near Port Angeles (Figure 5). As the HVDC Light® cables require burial, the route for the project was selected to follow existing municipal streets and utility rights-of-way. The advantage of following these existing corridors is that it significantly reduces the number of landowners involved in the project, and provides for greater public acceptance of the project by government agencies and the general public. Table 8 outlines the specific lengths for the project.

The marine route for the JDF Project crosses the Strait of Juan de Fuca to the Olympic Peninsula. A geophysical survey of the route carried out to review the seabed conditions indicated no potential submarine landslides or other features that would affect the performance of the cables following an earthquake (TRSI, 2006).

Table 8: Specific Data for Juan de Fuca Cable Project (from Sea Breeze, 2005)

	Marine	Terrestrial	
	HVDC Light®	HVDC Light®	HVAC
Length	34km across the Strait of Juan de Fuca	Approximately 12km on the Vancouver Island Approximately 3km near Port Angeles	Less than 500m from each of two converter stations to nearby substation
Capacity	574 MW rated	574 MW rated	> 574 MW rated
Type	±150 kV HVDC Light®	±150 kV HVDC Light®	3-phase AC
Converter Stations	150 m x 100 m (492.1' x 328.1') located near existing substations		

3.3.3 Project Financing Considerations

As for merchant transmission projects, the JDF Project would be developed using project financing. In this manner, the revenues from the project are used to pay down the debt from the project. The roles for the financing include the sponsor, the equity partner, and the debt partner. Sea Breeze Pacific – Regional Transmission System is the sponsor, carrying out concept development, feasibility studies, and permitting through to the negotiation of the EPC contract with ABB, Inc. (see Table 2). Energy Investors Fund is the equity partner, with an $8 million loan placement for development and permitting of the project through to final design, in exchange for project equity. Société Generalé is acting as the financial advisor, and would arrange the debt partner once contracts for service are established (Sea Breeze, 2006).

For private financing of transmission lines, uncertainty is an important consideration. As required for all merchant transmission line projects, an open season was held for the transmission services on the Juan de Fuca line (transmission and ancillary services). The open season received one bidder. In accordance with the Order from FERC, Sea Breeze is able to negotiate bilateral agreements with individual utilities following the conclusion of the Open Season. Without contracts for service, any private transmission line could not be financed (and likely not built). In conjunction with project contracts, financial guarantees are an important part of financial arrangements for the project, to ensure that no one party has to assume the full credit risk for the project. Typically, providing a combination of guarantees and undertakings (credit notes) provides a bankable credit sufficient for lenders.

Sea Breeze developed a novel approach for the financial aspects of the proposal to BCTC and BC Hydro and BCTC for transmission service on the JDF Project. Specifically, Sea Breeze offered the south-to-north service to BCTC (import to BC) for a lump sum price, at 75 percent of the capital cost for the VITR Project. This would require the BCUC to order negotiations between BCTC and Sea Breeze for the project. Sea Breeze would retain the rights to negotiate for north-to-south (export from BC) capacity on the line, as well as ancillary services on the line. It is important to note that this offer is not dependent on the cost of JDF for financing, but rather the avoided cost of VITR (Sea Breeze, 2006a).

Table 9: Financing summary for JDF Project (Sea Breeze, 2006)

JDF Costs and Benefits	Estimated Cost[1]
Direct Costs (to BCTC/BC Hydro ratepayers)	($ millions)
Project Definition	**75% of VITR**
Project Implementation	**75% of VITR**
Contingency	*Not applicable*
Operations and Maintenance	*Not applicable*
TOTAL COSTS	**195.8**

Notes: 1. The total costs for JDF are based on 75% of the total costs (development plus implementation) for the VITR Project.

3.3.4 Regulatory Applications

As the Juan de Fuca Project links substations in Canada and the US, it is an international power line and falls under the jurisdiction of the National Energy Board (NEB) in Canada, and the Federal Electricity Regulatory Commission in the US.

The National Energy Board does not regulate tolls, but rather reviews project justification to determine if the facilities will be 'used and useful'. The NEB also reviews all environmental aspects of the project, and technical issues as they relate to project performance and compliance.

In the US, Bonneville Power Authority has the responsibility for reviewing the environmental aspects of the JDF Project for compliance with federal regulations and the City of Port Angeles has the responsibility to review the application for compliance with state and local regulations.

3.3.5 Timeline for Development

Development work on the Juan de Fuca Project started in the fall of 2004, and into 2006 (Sea Breeze, 2005b). The timeline for the project is shown in Figure 8. As the project was started before both the VITR and VIC Projects, the timeline for development has the project in service before the peak demand on Vancouver Island in winter 2008.

Task Name	Start	Finish
Concept Development	11/17/03	3/15/04
Feasibility Studies	3/15/05	5/13/05
Preliminary Engineering	5/13/05	6/30/05
CPCN Permitting	8/30/05	2/17/06
Environmental Permitting	**9/5/05**	**12/12/06**
Planning, Budgeting	**12/27/05**	**5/9/06**
Detailed Engineering	5/9/06	9/14/07
Construction	11/13/06	1/18/08
Commerical Operation Date	1/21/08	1/21/08

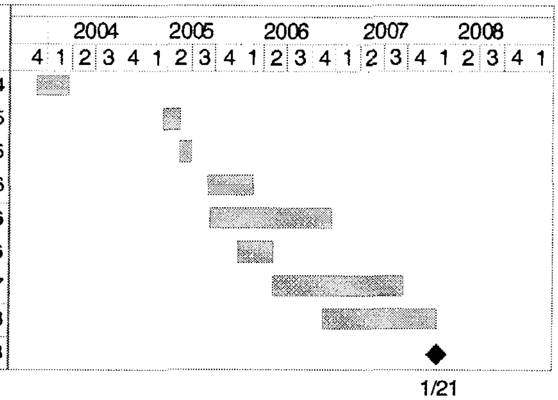


Figure 8: Timeline for the development of the Juan de Fuca Project

3.4 Temporary Bridging Measures for Vancouver Island

Bridging measures, or means to provide reduce the peak demand or increase generation in the event of an emergency, were contained in the BCTC proposal for VITR. The measures included the use of real-time monitoring to increase the capability of the existing transmission lines to Vancouver Island; potential improvements to the existing HVDC system to extend its service life for perhaps three years; and working with large industrial power customers on Vancouver Island to reduce electricity demand during times of peak load (BCTC, 2006a). Such bridging measures are considered a short-term solution and are not a substitute for transmission reliability under NERC guidelines (BC Hydro, 2006b).

4 NON-FINANCIAL COMPARISON OF ALTERNATIVES

The comparison of the Vancouver Island Transmission Reinforcement (VITR), Vancouver Island Cable (VIC), and Juan de Fuca Cable (JDF) Projects must consider many non-financial aspects that relate to the acceptability and relative merits of the projects. This chapter discusses the evaluation of the projects according to four criteria that reflect the issues for regulatory approvals. These non-financial criteria are central to the overall socioeconomic evaluation of projects; specific issues for permitting typically include reliability, technical risk, as well as potential impacts on public health, safety, and the environment.

The criteria used in evaluation are based on the author's assessment of information exchanged during the VITR Proceeding (BCUC, 2006b) and the mandate of the BCUC (BCUC, 2006a). Considerable information was provided by both BCTC and Sea Breeze regarding many non-financial aspects of the projects to the BCUC, particularly relating to the public health, safety and reliability of the respective alternatives. Evaluating these using specific weights for each criterion allows for the comparison of mixed criteria. Many of these criteria have a recognized threshold or standard, and the likelihood of meeting this standard is the evaluation is a useful metric for comparing the projects.

Table 10 lists the criteria, as well as the weights and ratings for each of the three projects. The weights are expressed as a percentage, and sum to 100 percent. The ratings for each criterion represent the subjective probability that the acceptable threshold or standard will be achieved. Sections 4.2.1 through 4.2.4 describe the weights and subjective probability ratings in Table 10.

Table 10: Comparison of Alternatives using Subjective Probability Ratings

Criteria	Weight	VITR	VIC	JDF
SAFETY				
Public Health	25	90	97	97
Accidents and Malfunctions	20	95	98	98
RELIABILITY				
Operational Reliability	25	70	95	95
Required Operation Date	30	20	20	90
Weighted Total Impacts	100%	**60.85**	**71.00**	**95.50**

Note: Ratings are based on the subjective probability that the standard or threshold for the criterion can be achieved for a given project. For example, a rating of 70 indicates that there is an estimated 70% probability that the project as proposed will meet the required standard or threshold.

4.1 Selection of Weights for Ranking

The selection of weights for the rankings was carried out by considering the mandates for both the British Columbia Utilities Commission (BCUC) and the National Energy Board (NEB). The BCUC has the mandate to "ensure that customers receive safe, reliable... energy services at fair rates" (BCUC, 2006a). In a similar fashion, the NEB has the mandate to "promote safety and security, environmental protection, and efficient energy infrastructure and markets" (NEB, 2006). The selection of weights in Table 10 reflects the mandates of the BCUC and the NEB.

4.2 Probability Ratings

4.2.1 Public Health

The potential impacts to public health relate to both acute and chronic effects to individuals and the public at large associated with the construction and operation of the facilities. Acute effects are the result of disruption, disturbance, and inconvenience to residents in the immediate area of a project. For buried cables, these effects are typical of many common linear infrastructure projects, such as water or sewer pipelines, fibre-optic lines, and are largely mitigated through careful project planning and public consultation.

Chronic health effects from electrical transmission lines are related to the electromagnetic field (EMF) exposure. A common perception in the public that the exposure to EMF can cause cancer; some studies support this notion. Draper et al (2005) studied children living near transmission lines in the United Kingdom and found a statistically significant link between the EMF from AC transmission lines has been linked to childhood leukaemia. Other scientists point out that there are difficulties in reaching definitive correlations or causal relationships due to the fact that it is a rare disease affecting approximately 1 in 3600 children, and the additional factors (air pollution, income, etc.) likely confound any study. The approach of some governments and agencies can be precautionary; for example, the Canadian Cancer Society has recently recommended that parents reduce the exposure of their children to EMF from transmission lines, despite the lack of conclusive evidence that EMF is carcinogenic.

It is important to note that the studies for the potential health effects of EMF relate to the fluctuation of the fields, and that static fields are generally understood to be a lesser a health risk. For example, static fields are generated by some types of medical MRI equipment and industrial welding equipment. Studies to examine the effects of the fields from these devices have shown that fields that are several orders of magnitude greater than the magnetic field of the earth do not cause acute effects in workers with routine and prolonged exposure.

The International Commission on Non-Ionizing Radiation (ICNRP) has produced standards based on studies for both fluctuating electromagnetic fields from AC transmission lines and static magnetic fields from DC transmission lines (ICNRP, 2003). For fluctuating EMF, the safe limit depends on the frequency of the field. For 60 hertz, the frequency of AC transmission lines in North America, the EMF limit is 833 milliGauss. For static magnetic fields from DC transmission fields, the safe limit set by ICNRP is 40,000 milliGauss. Health Canada has no specific guidelines or thresholds, since it considers the scientific studies inconclusive on the link between typical exposures and health problems (BCUC, 2006b). In Europe, recent news reports indicate that lower threshold limits for AC transmission lines may likely come into effect (Fleming, 2006).

It is also important to note that previous transmission line projects before the BCUC have considered the issue of the potential health effects of EMF (BCUC, 2006c). These include the CPCN Applications for transmission lines in the Kootenays, the Lower Mainland, and the southern Okanagan, where the Commission considered the EMF from transmission lines and concluded that there was no evidence to support the contention that the fields from electrical transmission lines are a public health risk.

Public health could also include the anxiety caused to residents and communities from a project, whether from concerns about potential decreases in property values or other impacts. Since these issues are closely tied to the perceptions of the public about the project, open and meaningful consultation can reduce this source of stress (BCUC, 2006b). In such situations, public consultation is an important means to develop trust in the community.

4.2.1.1 VITR Project (HVAC Technology)

Since the Vancouver Island Transmission Reinforcement Project proposes to use conventional AC technology, the expected strength of the EMF and the expected health effects were the subject of considerable discussion and debate during the BCUC proceedings. The expected limit was given as maximum of 188 millGauss directly under the aerial transmission lines[19]. Comparing this to both the ICNRP guidelines of 833 milliGauss and the expected limit in Europe of 400 milliGauss, and considering that some doubt remains about the ability of future scientific studies to prove that fluctuating EMF is not a health risk, the probability of meeting the threshold for public health is subjectively estimated as 90 percent.

[19] This maximum corresponds to the operation of both Phase 1 and Phase 2 upgrades of the VITR route, with two 230kV circuits.

4.2.1.2 VIC and JDF Projects (HVDC Light® Technology)

With the high voltage direct current (HVDC) technology proposed for both the VIC and JDF Projects, a very small electromagnetic field and a static magnetic field during occurs during operation. The strength of the static field is calculated as 560 milliGauss directly over the buried cables, which is 0.14 percent of the ICNRP limit for static magnetic fields of 40,000 milliGauss. Based on this extreme gap between the expected levels during operation and the ICNRP standard, the probability of both VIC and JDF meeting the threshold for public health is subjectively estimated as 98 percent.

4.2.1.3 Summary

All three projects meet the requirements for public health and safety. However, the VITR Project has greater impacts related to the use of older alternating current technology. While this does not alter its ability to meet the worldwide standard, the perceived effects are such that the public opposition to electrical transmission lines often focuses on potential health effects from fluctuating EMF. Such opposition can affect permitting timelines; see Section 4.2.4.1, below.

4.2.2 Accidents and Malfunctions

Electrical transmission facilities can present dangers to workers and individuals through accidents or malfunctions. Accidents can occur during maintenance or operations, leading to injury or death. Malfunctions during operations could pose a danger to workers and others. It is important to note there is no set threshold for the safety risk posed by accidents to workers. BCTC, on their website, has set a corporate goal for safety related to 23 loss time accidents per year.

Risk reduction for accidents is commonly carried out through both design that meets specified standards which incorporate safety considerations (such as those from the Canadian

Standards Association) as well as specialized worker training and public information campaigns for education regarding the potential dangers of transmission facilities.

4.2.2.1 VITR Project (HVAC Technology)

As a transmission line with a sizeable aerial component, several types of accidents and malfunctions are possible with the VITR Project. One common type of accident relates to the safety of workers and others around energized transmission lines. The "Seven Steps to Electrical Safety", (BCTC, 2006c), contains information for workers and others carrying out activities in the immediate vicinity of transmission lines, and can significantly reduce (but not eliminate) potential accidents.

In terms of malfunctions, the AC technology proposed for the VITR Project is very similar to the technology used in many other parts of British Columbia. Thus, any malfunctions are reflected in the historical performance of the existing systems and are considered as part of the calculations regarding operational reliability, as discussed in Section 4.2.3. Based on common understanding of aerial transmission lines and the mitigation strategies that are used, the VITR Project was judged to have a 95 percent probability of meeting the acceptable rates for accidents and malfunctions.

4.2.2.2 VIC and JDF Projects (HVDC Light® Technology)

Potential accidents related to the HVDC Light® technology proposed for both the VIC and JDF Projects consist of accidental breakage in the cables due to digging activities around the installed cables, and accidents during maintenance activities of the converter stations. With respect to "dig-in" failures, both the VIC and JDF Project proposals include a concrete cap above the buried cables, at locations where nearby excavation was likely to occur (such as in municipal rights-of-way, where other utilities also exist). In other areas, warning tape would be placed over the cables. As-built drawings would be supplied to municipal engineering departments, as well as provincial authorities that operate BC OneCall, a utility referral service that identifies existing underground utilities (such as natural gas pipelines) for contractors and municipal work crews that carry out excavation activities in municipal streets.

Although malfunctions are possible with any transmission system, HVDC Light® technology is recognized as reliable. In fact, HVDC Light® technology is used to stabilize electrical systems to prevent cascading outages and voltage fluctuations, since the converter stations . Thus, the HVDC Light® converter stations are inherently less prone to malfunctions than the conventional AC technology. Based on the mitigation proposed to reduce the likelihood of dig-in failures and the robust design of the HVDC Light® system, accidents and malfunctions are not expected. The probability of the system meeting the expectations is subjectively estimated as 95 percent.

4.2.2.3 Summary

All three projects meet the requirements related to accidents and malfunctions. However, the additional reliability afforded through burial provides slightly greater protection against many types of potential accidents and the increased stability inherent in the HVDC Light® system provides increased protection against malfunctions compared to conventional AC transmission systems.

4.2.3 Operational Reliability

Reliability for an electrical system depends both on the adequacy of the system to carry the necessary amount of power to meet peak loads and the security of the system to continue to provide service following sudden disturbances. The requirements for the reliability of electrical transmission systems are voluntary, and set by the National Electricity Reliability Council (NERC) and the Western Electrical Coordinating Council. BCTC has the responsibility of ensuring that the transmission system in British Columbia meets reliability standards. BC Hydro acknowledges that the existing system does not meet the reliability standards for Vancouver Island (BC Hydro, 2006a).

The method to assess adequacy in terms of reliability can be carried out using probabilistic studies to determine the amount of energy that is not delivered under specific scenarios. These studies calculate the Expected Energy Not Served (EENS) and are carried out by BCTC to evaluate different options for planning. These studies calculate the amount of power that is not delivered by simulating forced outages and natural events over a specific period of time. For example, previous EENS studies regarding electricity supply on Vancouver Island concluded that a 230kV transmission line provided the best option for reliability (Li, 2003). As with many types of studies, the inputs to an EENS study must be correct to ensure the results are realistic. The BCUC target for operational reliability is less than 2.10 hours per year, or 99.97 percent availability[20] (BCTC, 2006c).

In terms of electrical system reliability, these are often expressed in terms of the ability of a system to withstand the loss of a single element. For transmission this means that the loss of a single transmission line or generation facility does not affect the ability to serve customers. This is commonly known as the N-1 reliability requirement of the NERC. The specific standard depends on the voltage and capacity of the transmission line in question. It is understood that newer standards are currently in development that would provide greater security for multiple contingencies (also known as N-2[21]). The N-1 criterion (and the N-2 criterion if it is implemented) is a threshold that must be met as part of overall transmission planning and operations (Aggarwal, 2005).

[20] BCTC acknowledges that this outage rate does not include generator outages, and measures only the time the transmission system is not able to handle capacity requirements. This method is different than the standard used by other utilities in Canada (BCTC, 2006c).
[21] The N-2 criterion is accompanied by requirements to contain the initial transmission failure in the local area to prevent cascading failures into larger areas; to initiate planned load shedding and take some loads off line; and for incumbent utilities to carry out cost-benefit analyses for excessive load shedding (greater than 300MW).

4.2.3.1 VITR Project (HVAC Technology)

The operational reliability for the VITR Project is dependent on the scheduled maintenance required for the substation equipment, as well as the exposure of the aerial and marine cables to damage from natural events (including seismic events) or vandalism. The scheduled maintenance for the 230kV AC equipment proposed by BCTC involves an estimated forced outage rate of 1800 to 2200 MWh per year, equating to a rate of 2.59 percent (Li, 2005). The repair time for the VITR system is estimated as 383 hours (16 days) for the aerial portion of the transmission line and approximately 2,160 hours (90 days) for the submarine cables. The longer time for submarine cable repair is due to the working assumption that a cable ship that is capable of repair is not available when the break in the cable occurs.

With respect to security, the operational reliability of VITR depends on whether the system can withstand natural and other events, such as seismic and extreme wind events. While transmission towers are commonly designed to withstand extreme wind events, catastrophic earthquakes are not easily mitigated through design measures. The VITR substation in Delta, the existing Arnott Substation, has loose soils that are prone to large ground movements and liquefaction in the event of a large earthquake. BCTC agrees that the area will suffer some damage in the event of an earthquake, but repairs can easily be carried out to bypass the substation and restore power (BCTC, 2006b). However, an earthquake that is large enough to damage the Arnott Substation will also likely damage other infrastructure in the area (roads, bridges, and possibly other transmission lines). Hence, access to the site would likely be constrained and the safe mobilization of equipment may not be possible. For the submarine cable route, VITR passes across Roberts Bank, a steep submarine slope area that has experienced catastrophic landslides in the past (BCTC, 2005a). Although no historic submarine landslides were noted in the specific area of the VITR route, there is a possibility that the conditions could exist for such a failure in the event of a large earthquake. It is also important to note that if a large earthquake were to occur, the continued operation of the transmission system would likely be vital to restoration of other services and infrastructure on southern Vancouver Island.

Extreme wind events and forest fires are more likely to occur than seismic events, but measures to prevent damage can be included in the design and construction of the transmission towers. Although ice storms and hurricanes are a common cause of aerial transmission line damage (Five towns weigh, 2005), these weather events are extremely uncommon in the Lower Mainland and Vancouver Island. In terms of forest fires, a recent wildfire outbreak on Galiano Island created a potential hazard for the existing transmission lines to Vancouver Island (Dickenson, 2006).

Comparing the maintenance requirements and natural events such as seismic movements and extreme wind events, the most limiting factor for reliability is the ability of the system to withstand large seismic events. Based on these considerations, probability of the VITR meeting the requirements for operational reliability is subjectively estimated as 70 percent.

4.2.3.2 VIC Project (HVDC Light® Technology)

In terms of scheduled maintenance activities, the HVDC Light® technology requires a higher frequency of maintenance than conventional AC systems. Based on information provided by ABB, the availability of the system is greater than 95 percent, with the remainder occupied by scheduled maintenance activities in the converter stations. Based on an EENS study carried out by BCTC, the difference between the availability of the facilities was calculated as 4 percent for power levels less than 540MW[22].

The route selection for the VIC Project was carried out to avoid, to the extent possible, seismically unstable areas. In addition, since the endpoints of the project (and thus the converter

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[22] At power levels greater than 540MW, the difference between the two projects produces a marked difference in the expected energy not served, and the VITR Project has an 15% to 32% higher availability, based on either pessimistic or optimistic assumptions about the VIC project (Li, 2005).

stations) are located in areas that are seismically stable, large seismic events are not expected to affect operation. One area of potential liquefaction in the Serpentine and Nicomekl Valley was investigated as part of the preliminary engineering on the project, and ground movements were expected to be limited, and likely not to affect the performance of the cables following an earthquake (Sea Breeze, 2005c).

By virtue of its underground installation, the HVDC Light® cables are protected from extreme weather events and trees. However, as they would be installed in suburban streets, there is the potential for damage from incautious excavation for adjacent works. In terms of the frequency of damage, BCTC reported three dig-in failures for its underground transmission facilities which total 140 km during the 45 years of their operation.

Reducing the risk of dig-in failures for the VIC Project is similar to natural gas pipelines in suburban streets, where some risk exists for rupturing a line during excavation activities. In these circumstances, the risk is mitigated to acceptable levels through standard operating procedures which consist of: careful planning for proposed works; identification of gas line locations prior to excavating; and having gas line company representatives on site during excavation. In addition to these measures, Sea Breeze proposed to install a concrete cap above the cables as a means to protect the cables from excavation equipment.

Based on the maintenance schedule, the reduced seismic risk, and the relatively low potential for dig-in failures, the operational reliability for the VIC Project was subjectively estimated as 90 percent.

4.2.3.3 JDF Project (HVDC Light® Technology)

The HVDC Light® technology for the JDF Project is the same as for the VIC Project, and thus the maintenance schedules are identical. Thus, the 95 percent availability for the converter stations, and the comparison to the VITR Project, are very similar.

In terms of seismic concerns and dig-in failures, the JDF Project is marginally more reliable. The route for JDF does not contain areas that are prone to liquefaction or landslides, and as such, seismic events are not expected to damage the cables or converter stations. The potential for dig-in failures is also greatly reduced for JDF, since the length in suburban streets is substantially less than the for the VIC Project. The operational reliability for JDF is estimated as 95 percent for both adequacy and security.

4.2.3.4 Summary

The operational reliability differs for the VITR is less than for the VIC and JDF Projects. The VITR Project is the least reliable, due to its above-ground technology and its marine route through an area that is potentially unstable following seismic events. The VIC and JDF Projects are more reliable, due to the buried installation and the stable marine routes posing less risk.

4.2.4 Required Operation Date

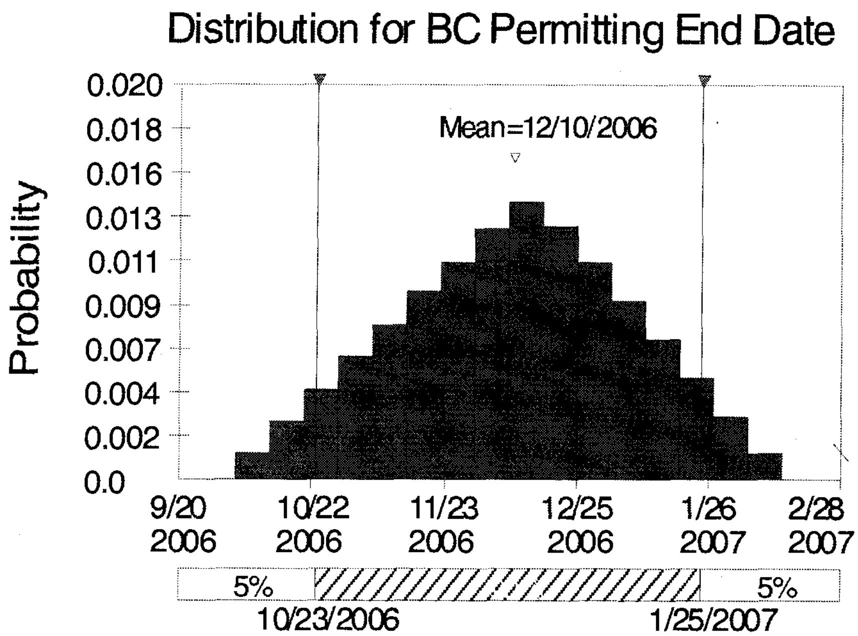
Both to permitting and project implementation can significantly delay the in-service date for a transmission project, and thus miss the required operation date. With respect to permitting, both the environmental and social aspects can significantly affect the timelines for approval. Implementation can be affected by constraints that arise during the permitting process, such as fisheries timing windows for marine construction, or as a result of construction issues, such as the availability of key components or equipment for installation. This section discusses the potential for delays to the required in-service date of October 2008 and evaluates the project schedules to determine the probability that the projects will not be complete on-time.

To consider the potential effects of such delays, the gantt charts for the projects (Figure 6 to Figure 8) were modified to include task dependence and uncertainty. The software package @Risk for Project (Palisade, 2005) was used to include probability associated with specific activities for the projects. With probability incorporated into the various tasks, repeated simulations were used to determine in-service dates based on task dependence and the probability distribution function representing the length of time to complete the activities. A comparison of the expected completion dates with the requirement for project completion by October 2008 provides a probability of project delay, and a basis for comparison of the projects.

To incorporate uncertainty into the analyses of project schedules, triangular probability distributions were used to represent the probability of a particular finish date or duration for a task. Many types of probability distributions[23] are possible, and numerous types are available in @Risk for MS Project (Palisade, 2005). Triangular distributions are suitable for subjective probability estimates, since it is often possible to bound the estimates for a parameter by selecting the most likely value, the least possible value, and the greatest possible value, and the largest possible value. Figure 9 shows an example triangular probability distribution function for the parameter BC Permitting, used in the VITR Project Model. Note that this includes property acquisition for the underground right-of-way in South Delta.

Note that these probabilities are subjective in nature, simply because the criterion that is necessary for creating a probability density function – repeated trials for a given situation, or similar situations – is not available for the project tasks. Thus, these probabilities differ from objective probability distribution functions that are fitted to statistically significant data sets of actual events (Albright et al, 2003).

[23] Common types of probability density functions for actual data include normal, logarithmic (lognormal), and extreme value distributions. For predictive probabilities, triangular, uniform, and beta distributions are typically used.



Note: Probability distribution reflects minimum (earliest) finish date of 10/01/2006, most likely finish date of 12/14/2006, and maximum (longest) date of 2/15/2006.

Figure 9: Example probability distribution for estimate for the completion of permitting

4.2.4.1 VITR Project (HVAC Technology)

During the BCUC review of the VITR Project, permitting and installation issues were examined. For permitting, the issues of property rights and environmental permitting were explored. In terms of implementation, the manufacturing of the marine cable, its installation, and potential public opposition to delay or cancel the project were discussed.

The preferred option for VITR Project, as put forward by BCTC, involved the underground installation within an existing aerial transmission right-of-way in Tswawwassen[24] that passes through the back yards of numerous residents. As BC Hydro sold of the subsurface rights some years ago, it would be necessary for BCTC to either reach new agreements with these

[24] This was "Option 2" in terms of the route and installation options put forward by BCTC in the VITR Project Application.

residents for construction of the underground line or expropriate these rights from the residents. Since BCTC does not have expropriation powers under the Utilities Commission Act, it would rely on BC Hydro to take this action[25]. Given that the property owners became organized and actively intervened in the VITR Proceeding with their own counsel, BCTC indicated that expropriation would be needed for timely project completion, and asked the Commission for a 90 day negotiation period with the property owners as a means to meet the project schedule. BCTC indicated during the Hearing that the construction of overhead lines through the Tswawwassen would not require new right-of-way agreements and thus it would not be subject to the same schedule risks as the preferred option.

Environmental permitting was also an issue in the Hearing, and raised additional uncertainty regarding further permitting activities. BCTC requires environmental approval from the BC Environmental Assessment Office, a separate regulatory process that was started concurrently with the CPCN Application before the BCUC. One particular issue for the environmental approvals for the VITR Project is the installation of the marine cables in the foreshore area. Such habitats require extensive study to understand the potential damage during cable installation and operation, and negotiation for compensation with the Department of Fisheries and Oceans. The seasonality and potential environmental constraints associated with cable installation in the marine foreshore could introduce significant delays. In addition, the VITR Project passes through US waters, and US permits are also required which can take longer than Canadian permitting.

In terms of project implementation, the manufacturing and installation of the marine cable as well as potential public action are issues that could affect the project construction timelines. The marine cable must be designed and manufactured under a tight timeline, in an

[25] There were differing legal opinions on whether BC Hydro could expropriate property rights on behalf of BCTC, and thus some regulatory uncertainty exists regarding the process of expropriation (BCTC, 2006a).

industry that is largely operating at capacity. Further, there are only two ships in the world that are able to deliver and install this cable, and thus reserving a ship for installation could cause delays to the project (Sea Breeze, 2006b).

Potential public action against the project could also cause delays. As observed for the Vancouver Island Gas Project, public interest groups were successful in obstructing the CPCN decision and causing considerable delays to the project. Given the organized groups that opposed the VITR Project, it is possible that an appeal would be sought which could delay the project significantly.

Given these considerations, the activities in the gantt chart for the VITR Project (Figure 6, Section 3.1.5) were separated for the project components (overhead, underground, marine) and assigned probability distribution functions for simulations. Table 11 contains the dates and distributions assigned for the analysis.

Figure 10 contains the VITR Project schedule used for the analysis. Along with the probabilities, the task dependence defines the order of completing tasks on the project. For example, marine cable installation cannot start until all the permitting has been carried out. By sampling the probabilities defined in Table 11 above, and using the tasks as linked in Figure 10, the commercial operation date for the project was determined.

Repeated sampling of the distributions, incorporating the task dependencies, leads to repeated calculations of the commercial operation date for the VITR Project. These results can be expressed as a probability distribution function, Figure 11, showing the expected completion date. Analysis of Figure 11 indicates there is a 1.7 percent chance that the project will be complete in 2008, with the mean completion date calculated as May 1, 2009. The analysis shows that the project is likely to start operation in 2009, well after the target completion date of winter, 2008.

Table 11: Task Data for VITR Project Probabilistic Schedule Analysis

Name	Variable	Distribution
BC Permitting	Finish Date	TRIANG(10/01/2006, 12/14/06, 2/15/07)
US Permitting	Finish Date	TRIANG(5/1/2006, 8/25/06, 12/15/06)
Planning, Budgeting	Duration (days)	TRIANG(38, 40, 44)
EPC Contract	Duration (weeks)	TRIANG(15, 18.6, 25)
Detailed Engineering	Duration (weeks)	TRIANG(75, 80, 90)
Supply and Installation	Duration (weeks)	TRIANG(105, 130, 140)
Detailed Engineering	Duration (weeks)	TRIANG(75, 87, 105)
Procurement and Contracts	Duration (weeks)	TRIANG(27, 30, 33)
Construction	Duration (weeks)	TRIANG(75, 87, 100)
Detailed Engineering	Duration (weeks)	TRIANG(110, 120, 150)
Contract and Procurement	Duration (weeks)	TRIANG(17, 19, 21)
Construction/Duration	Duration (weeks)	TRIANG(62, 70, 85)
Detailed Engineering	Duration (weeks)	TRIANG(80, 88, 110)
Procurement and Contracts	Duration (weeks)	TRIANG(50, 58, 70)
Construction/Duration	Duration (weeks)	TRIANG(25, 35, 50)

Note: Triangular probability distribution functions are represented by values in the range of (minimum possible, most likely, maximum possible). See Appendix A for a discussion of sampling probabilities for analysis.

This analysis indicates that there is a considerable chance of delay for the project. The schedule analysis indicates that the tasks of BC Permitting as well as marine cable Supply and Installation are on the critical path for completing the project. Terrestrial overhead construction is also on the critical path, such that tight timelines for both the marine and terrestrial works must be met for the project to be in service by the end of 2008. Other components of the project, namely the terrestrial underground construction and the substation construction, are seldom on the critical path during the simulations.

Based on the analysis of project schedules, the VITR Project is judged to have a 20 percent probability of meeting the required operation date of 2008 due to the high likelihood of delays during permitting and implementation of the project.

Name	Duration	Start	Finish
Concept Development	19 wks	1/19/04	5/28/04
Feasibility Studies	21.4 wks	7/1/04	11/26/04
Preliminary Engineering	55 wks	4/19/04	5/6/05
CPCN Permitting	87.4 wks	11/4/04	7/7/06
Environmental Permitting	**581 days**	**12/10/04**	**3/2/07**
BC	116.2 wks	12/10/04	3/2/07
US	73 wks	4/4/05	8/25/06
Planning, Budgeting	40 days	7/10/06	9/1/06
Marine Component	**743 days?**	**9/4/06**	**7/8/09**
EPC Contract	93 days?	9/4/06	1/10/07
Detailed Engineering	80 wks	1/11/07	7/23/08
Supply and Installation	130 wks	1/11/07	7/8/09
Terrestrial - Overhead	**1020 days**	**8/1/05**	**6/26/09**
Detailed Engineering	87 wks	8/1/05	3/30/07
Procurement and Contracts	30 wks	4/2/07	10/26/07
Construction	87 wks	10/29/07	6/26/09
Terrestrial - Underground	**600 days**	**9/4/06**	**12/19/08**
Detailed Engineering	120 wks	9/4/06	12/19/08
Contract and Procurement	19 wks	12/15/06	4/26/07
Construction	70 wks	6/1/07	10/2/08
Substations	**781 days**	**10/4/05**	**9/30/08**
Detailed Engineering	88 wks	10/4/05	6/11/07
Procurement and Contracts	58 wks	4/23/07	5/30/08
Construction	32 wks	2/20/08	9/30/08
Commerical Operation Date	1 day	7/9/09	7/9/09

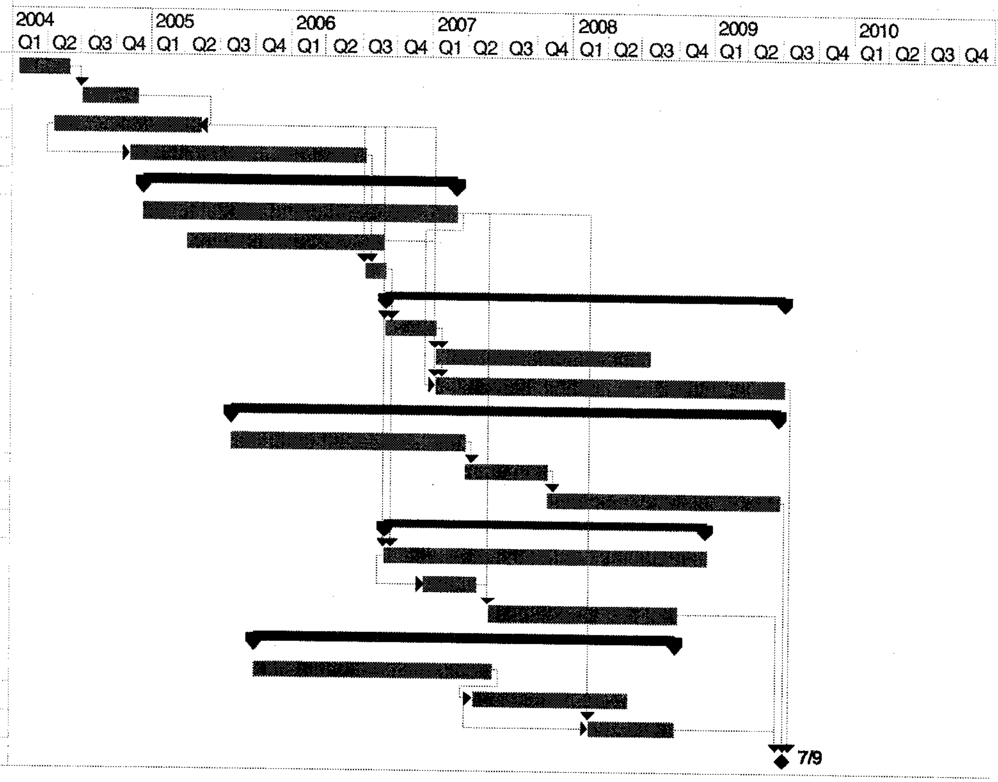


Figure 10: Project Schedule for VITR with project components and task dependence

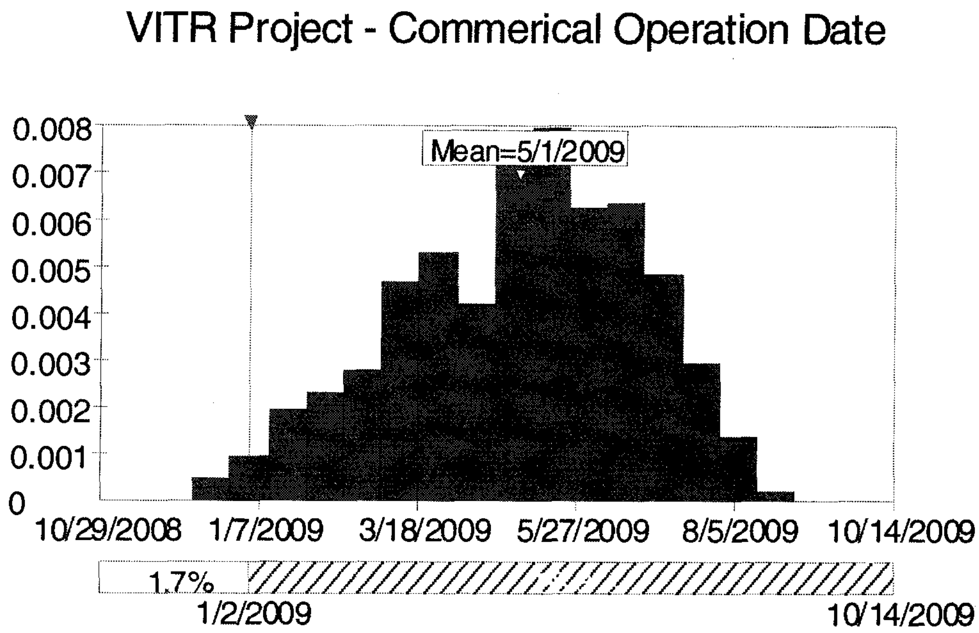


Figure 11: Probability density function of calculated completion dates for VITR Project

4.2.4.2 VIC Project (HVDC Light® Technology)

Similar to the probabilistic analysis that was carried out for the VITR Project, triangular distributions were incorporated into a schedule for the Vancouver Island Cable (VIC) Project to determine the expected commercial operation dates associated with various scenarios.

Table 12 contains the variables and probability distributions for the analysis. Note that triangular distributions, with values of minimum likely, most likely, and maximum likely reflect the uncertainties for the tasks. Note that this table contains Negotiations with BCTC, which must be carried out if a CPCN were granted to the VIC Project. Engaging ABB, Inc. with an EPC contract will shorten the timelines for design, manufacturing, and installation as the ABB engineers are able to utilize the knowledge from previous projects and start manufacturing the cables in advance of final design. In addition, ABB also has its own marine cable-laying ship, which is also expected to reduce the uncertainty regarding the marine installation timelines.

Table 12: Task Data for VIC Project Probabilistic Schedule Analysis

Name	Variable	Distribution
Negotiations with BCTC	Duration	TRIANG(20, 35, 45)
BC Permitting	Finish Date	TRIANG(12/15/2006, 2/15/07, 4/15/07)
US Permitting	Finish Date	TRIANG(1/15/2007, 2/15/07, 4/15/07)
EPC Contract	Duration	TRIANG(86, 96, 106)
Project Planning	Duration	TRIANG(90, 200, 300)
Cable Design / Mfg / Shipping	Duration	TRIANG(270, 310, 375)
Installation and Testing	Duration	TRIANG(115, 132, 180)
Cable Design / Mfg / Supply	Duration	TRIANG(290, 330, 390)
Detailed Engineering	Duration	TRIANG(210, 235, 260)
Construction / Installation	Duration	TRIANG(180, 205, 250)
Design / Mfg / Supply	Duration	TRIANG(310, 350, 425)
Construction	Duration	TRIANG(270, 310, 400)

As with the VITR Project Schedule analysis, repeated simulations were used to determine the expected commercial operation date for the VIC Project. Figure 13 shows the distribution of outcomes, as a probability density function with all in-service dates in 2009. Note that the mean is May 30, 2009 with is only a short time after the mean for the VITR Project.

The tighter grouping of the VIC Project completion dates compared with the VITR completion dates is due to the tighter timelines afforded by the EPC contract with ABB and the efficiencies related to design-build contracts.

Based on the results of this analysis, the VIC Project was judged to have a probability of 20 percent of meeting the operation start date of 2008. This is a result of the late start for the environmental assessments and the potential for prolonged property negotiations along portions of the route due to the numerous landowners involved.

Task Name	Duration	Start	Finish
Concept Development	7 days	8/5/05	8/15/05
Feasibility Studies	35 days	8/15/05	9/30/05
Preliminary Engineering	35 days	8/15/05	9/30/05
CPCN Permitting	124 days	1/17/06	7/7/06
Negotiations with BCTC	35 days?	7/31/06	9/15/06
Environmental Permitting	**333 days**	**3/19/07**	**6/25/08**
BC	308 days	3/19/07	5/21/08
US	322 days	4/3/07	6/25/08
Planning, Budgeting	**115 days**	**9/18/06**	**2/23/07**
EPC Contract	96 days	9/18/06	1/29/07
Project Planning	115 days	9/18/06	2/23/07
Marine Component	**499 days**	**1/30/07**	**12/26/08**
Cable Design / Mfg / Shipping	310 days	1/30/07	4/7/08
Installation and Testing	132 days	6/26/08	12/26/08
Terrestrial - Underground	**571 days**	**1/30/07**	**4/7/09**
Cable Design / Mfg / Supply	330 days	1/30/07	5/5/08
Detailed Engineering	234 days	1/30/07	12/21/07
Construction / Installation	204 days	6/26/08	4/7/09
Substations	**677 days**	**1/30/07**	**9/2/09**
Design / Mfg / Supply	354 days	1/30/07	6/6/08
Construction	310 days	6/26/08	9/2/09
Commerical Operation Date	1 day	9/3/09	9/3/09

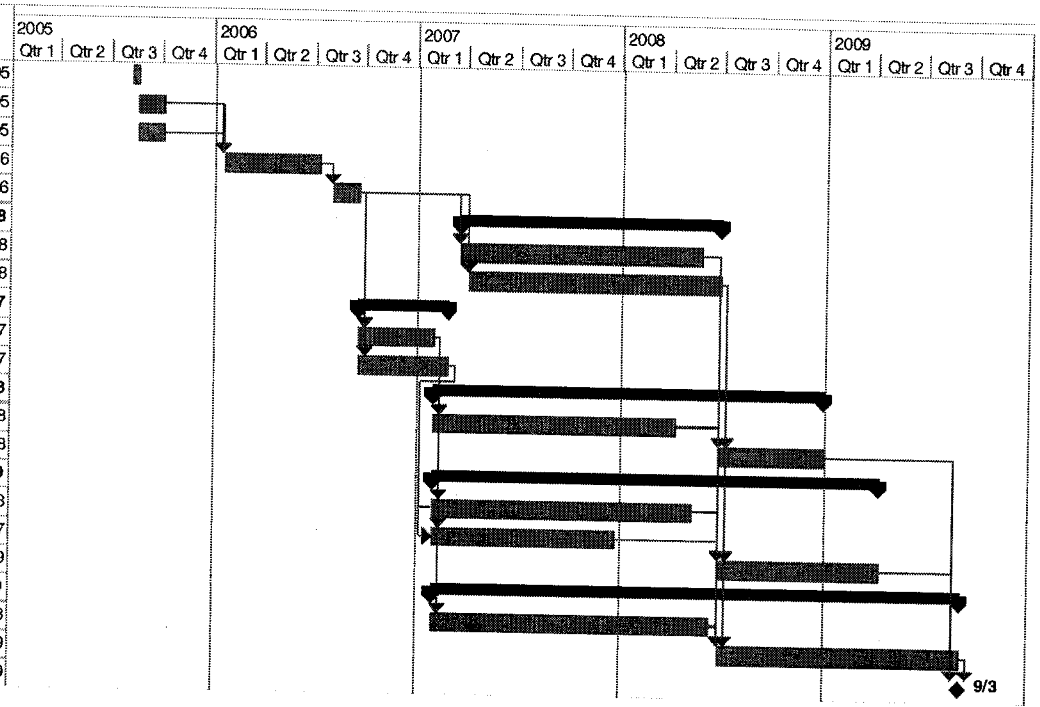


Figure 12: Project Schedule for VIC with task dependence

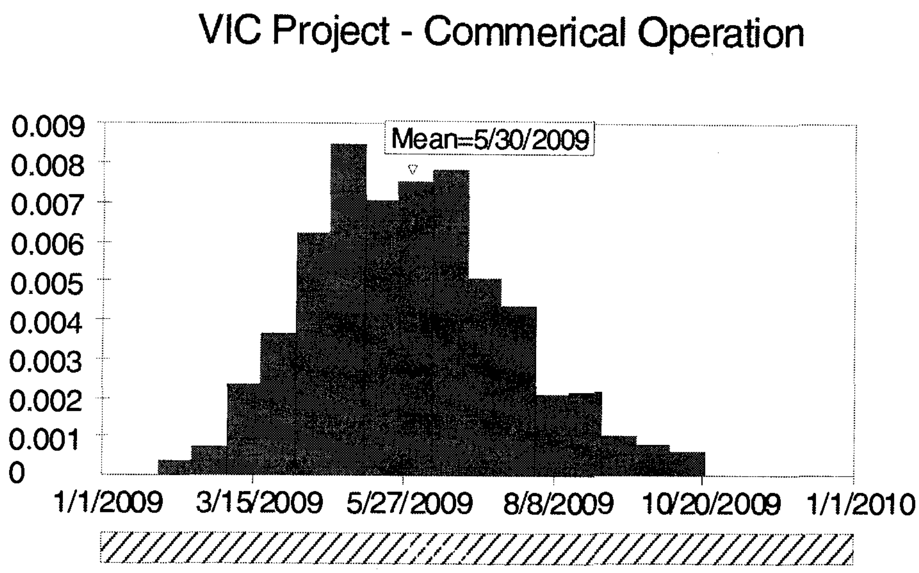


Figure 13: Probability density function of calculated completion dates for VIC Project

4.2.4.3 JDF Project (HVDC Light® Technology)

The Juan de Fuca (JDF) Project uses HVDC Light® technology similar to the VIC Project and thus has similar considerations in terms of the efficiencies gained through the EPC contract with ABB for design-build services. However, the JDF Project has to obtain a greater number of permits for interconnection with the substation in Port Angeles, shown collectively as US Permitting.

Similar to the analysis for the VITR and VIC Projects, uncertainty was incorporated into the JDF Project schedule using triangular probability distributions for component tasks. Table 13 lists the tasks and the distributions used in the analysis. Note that this schedule assumes that the contracts that are necessary to secure financing of the line are obtained prior to establishing the EPC contract. In this respect, the project schedule in Figure 14 represents an optimistic scenario for project, but one that is possible if negotiations are efficiently concluded with BC Hydro and BCTC regarding service on the line[26].

Table 13: Task Data for JDF Project Probabilistic Schedule Analysis

Name	Variable	Distribution
CPCN Permitting	Finish Date	TRIANG(8/20/2006, 9/10/06, 10/1/06)
BC Permitting	Finish Date	TRIANG(270, 305, 340)
US Permitting	Finish Date	TRIANG(280, 320, 360)
EPC Contract	Duration	TRIANG(86, 96, 106)
Cable Design / Mfg / Shipping	Duration	TRIANG(270, 310, 350)
Installation and Testing	Duration	TRIANG(115, 132, 150)
Cable Design / Mfg / Supply	Duration	TRIANG(290, 330, 370)
Detailed Engineering	Duration	TRIANG(210, 235, 245)
Construction / Installation	Duration	TRIANG(180, 205, 225)
Design / Mfg / Supply	Duration	TRIANG(310, 350, 390)
Construction	Duration	TRIANG(270, 310, 350)

4.2.4.4 Summary

Incorporating task dependence and probability into the schedules for the three projects allows for a comparison of the projects and the ability to meet the required operation date of December, 2008. Based on the VITR Schedule and incorporating the potential for delays due to permitting, property acquisition, or marine cable installation, the expected completion date is May 1, 2009 and it is very unlikely the project would be complete by the end of 2008. For the VIC Project, even though it started later than the VITR and JDF Project, the expected completion date is comparable to the VITR Project due to the efficiencies gained through private (or public-private partnership) development, particularly related to establishing an EPC contract with ABB. The JDF Project would very likely be finished in 2008, given the early start date, the shorter route, and the efficiencies of an EPC contract with ABB.

[26] Sea Breeze, in its testimony before the BCUC, stated that it was willing to continue with the development of the JDF Project without contracts from BCTC or BC Hydro (Sea Breeze, 2006b). In this sense, negotiations for service with either BCTC or BC Hydro are not necessary but on the critical path for the project schedule, and thus are not included in the JDF schedule model.

Task Name	Duration	Start	Finish
Concept Development	86 days	11/17/03	3/15/04
Feasibility Studies	44 days	3/15/05	5/13/05
Preliminary Engineering	35 days	5/13/05	6/30/05
CPCN Permitting	472 days	11/30/04	9/20/06
Environmental Permitting	**317 days**	**9/5/05**	**11/21/06**
BC	306 days	9/5/05	11/6/06
US	307 days	9/19/05	11/21/06
Planning, Budgeting	**97 days**	**6/29/06**	**11/10/06**
EPC Contract	97 days	6/29/06	11/10/06
Marine Component	**445 days**	**11/13/06**	**7/25/08**
Design / Mfg / Shipping	310 days	11/13/06	1/18/08
Installation and Testing	135 days	1/21/08	7/25/08
Terrestrial - Underground	**422 days**	**11/13/06**	**6/24/08**
Design / Mfg / Supply	319 days	11/13/06	1/31/08
Detailed Engineering	226 days	11/13/06	9/24/07
Construction / Installation	196 days	9/25/07	6/24/08
Substations	**477 days**	**11/13/06**	**9/9/08**
Design / Mfg / Supply	321 days	11/13/06	2/4/08
Construction	316 days	6/26/07	9/9/08
Commerical Operation Date	1 day	9/10/08	9/10/08

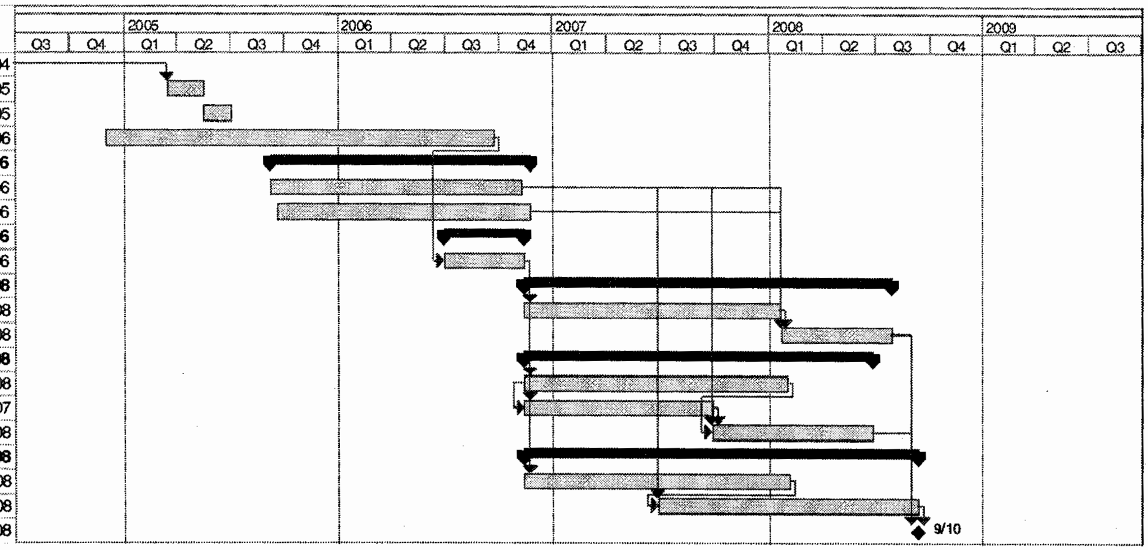


Figure 14: Project Schedule for JDF with task dependence

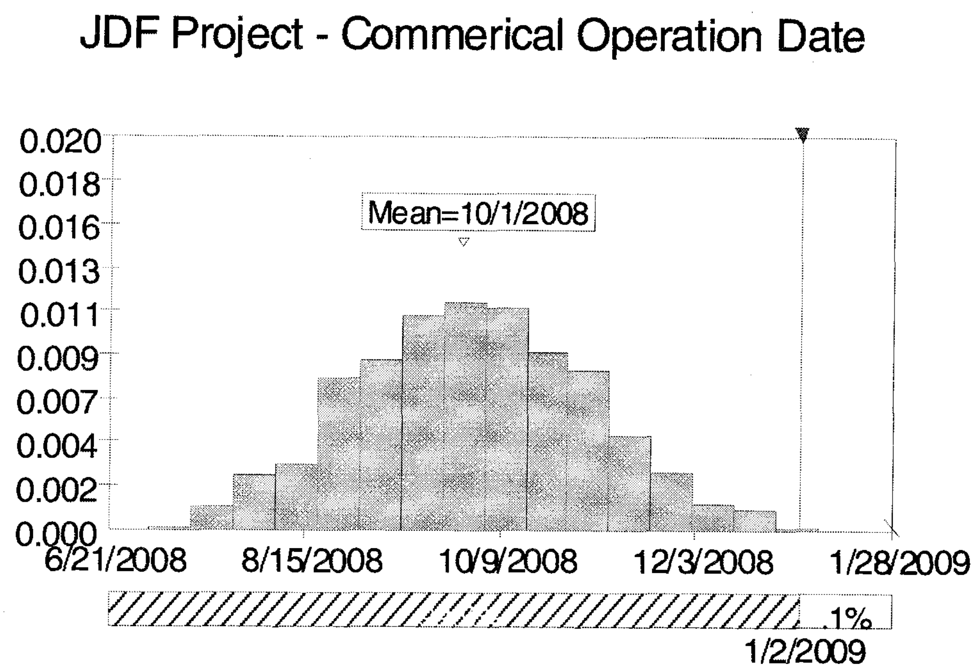


Figure 15: Probability density function of calculated completion dates for JDF Project

4.3 Summary

The comparison of non-financial criteria is important to establish the viability of a transmission project from a technical and regulatory perspective. Analyses of the projects were carried out to compare established thresholds for public health, accidents and malfunctions, operational reliability, and project in-service dates.

Based on these analyses, the VIC and JDF projects are estimated as having a marginally higher probability of meeting the thresholds for public health due to the lack of a fluctuating electromagnetic field. The two Sea Breeze projects are also estimated to have fewer accidents and malfunctions due to complete underground installation of the cables, and better reliability following a large seismic event. In terms of project schedule, the JDF Project appears to have significant advantages over both the VITR and VIC Projects. The expected earlier start date for the JDF Project appears due to the shorter terrestrial route, which equates to less time required for permitting and design. Also, the JDF route crosses two private properties that are owned by the same landowner, and it is likely that a negotiated settlement can be reached for an easement, given the existing transmission corridor and the land development. If a negotiated settlement cannot be reached, the expropriation process under the NEB is expedient and could be used to meet a tight project timeline if necessary.

A design-build contract for the HVDC Light® systems also appears to provide some additional benefits to shorten the schedule. This is due to the effective integration of design, manufacturing, transport, and installation for the cable system and converter stations. These efficiencies suggest the VIC Project would finish in roughly the same time frame as the VITR Project.

5 FINANCIAL COMPARISON OF ALTERNATIVES

This chapter evaluates and compares the financial aspects of the three transmission line project alternatives for southern Vancouver Island. Issues related to the technology for the projects and the different regulatory frameworks for each project are included in the evaluation, insofar as they affect the financial considerations of the projects.

5.1 Financing of Transmission Projects

Transmission line projects are generally financed using either "system" or "project" financing (Krellenstein, 2004). With system financing, the incumbent utility acts as a sponsor for the project, and guarantees repayment of the funds used for direct project costs. This is common for financing transmission line projects, with costs paid by all utility ratepayers. With system financing, it is relatively easy to obtain nominal rates of return for utility investors, provided the utility has a strong balance sheet since the revenues from other sources can help defray unexpected costs for transmission development. For this study, the Vancouver Island Transmission Project is funded through system financing by BC Hydro (BCTC, 2006a).

Project financing is used where an independent entity funds a transmission development through project-specific revenues. In the case of a public-private partnership, the revenues can take the form of very long term contracts with the incumbent utility, with relatively little risk. Alternatively, the revenues for the project may involve shorter term contracts that do not fully service the debt and thus some merchant risk related to payment of direct project costs. Both the VIC and the JDF Project would rely on project revenues for repayment of debt.

Project financing is almost always more expensive than system financing. This largely relates to the weighted average cost of capital (WACC) and the credit risk appraisal for third-party developers compared with the large utilities. Table 14 illustrates how the differing credit ratings affect the cash flow requirements for debt financing of a $100 million project (Krellenstein, 2004). In terms of financing structure, the significant equity required for private transmission developers also increases the cost of financing. Thus, the range in annual cost for project financing is from $16.5 to $7.9 million, with the least expensive costs associated with a high quality credit rating and 100 percent debt financing for a public utility without taxes.

Table 14: Annual financing costs for $100M project (summarized from Krellenstein, 2004)

	Financing Category	Financing Assumptions	Annual Cost
Private Transmission Developer	Project Financing with Merchant Risk	70% debt / 15% equity / 15% "B" loans credit rating: B WACC: 13.0%	$16.5 Million
	Project Financing with no Merchant Risk	75% debt / 25% equity credit rating: BB+ WACC: 9.5%	$13.9 Million
Incumbent / Operating Utility	System Financing with taxes (Investor-Owned Utility)	75% debt / 25% equity credit rating: BB+ WACC = 9.5%	$9.4 Million
	System Financing without taxes (Public Utility)	100% debt credit rating: A WACC: 9.5%	$7.9 Million

Notes:
1. Krellenstein notes that the spread between bond ratings fluctuates, and has ranged from 0.80% in early 2004 to 0.42% in late 2004. Accordingly, the costs given in the figures illustrate only indicative differences in costs for differing financing categories.
2. Calculations assume a 20 year amortization and a 12 year amortization for non-recourse debt, with no operating costs or tax benefits

Recent trends in project financing have allowed some institutions to offer blended finance portfolios and reduced debt service costs, particularly for public-private partnerships (Société Generalé, 2006). This is due to the ability of some debt partners to structure their portfolios such that the effective risk across all portfolios is less than the risk on an individual project.

5.1.1 Project Capital Cost

The capital cost for transmission line projects represent a considerable risk to projects. All three projects – VITR, VIC, and JDF – have some level of risk related to potential overruns during construction. The largest risks contributing to potential cost overruns were identified as financial risks related to currency commodity price fluctuations for overseas manufacturing of the transmission cables and other components. There was also some level of risk identified with the installation costs, however this was significantly smaller in scope and magnitude than the issues related to cables and components. For VITR, the marine cables alone were 55 percent of the total estimated project cost, while the HVDC Light® cables and converter stations were 92 percent of the VIC Project cost and a similar proportion of the JDF cost.

The risks associated with cost overruns can be considered and mitigated using several techniques in structuring the financing for the project (Nevitt and Fabozzi, 2000). These include the provision of additional capital from the sponsor; the negotiation of standby credit for the project; the use of fixed price contracts to provide certainty with respect to project development; as well as re-neogitation provisions in the lender's contract; or an escrow fund to hold funds until project completion.

5.1.2 Revenue Sources

A fundamental consideration in the project financing of transmission line projects is the sources of revenue for the project. There are typically three types of revenues from an electrical transmission line project: 1) the contracts for transmission service on the line, on both a firm and non-firm basis; 2) the contracts for providing ancillary services, such as voltage support; and 3) payments (or credits) for deferrals for the avoided cost of other transmission projects (that were proposed but not constructed).

Service contracts are typically structured as "take or pay" agreements, and are common for throughput on pipelines and transmission lines. Such agreements are also known as tolling contracts, a minimum-pay contract, or an all-events tariff. These essentially provide guaranteed service for a set rate, with an escalation factor to consider maintenance and some operational risks. For a utility project with system financing, such as the VITR Project, service contracts are not required. For private or public-private partnerships, the service contracts[27] allow for lenders to evaluate almost all financial aspects of the project, and thus form the basis for securing debt financing for the project.

Revenue from ancillary services is often a second type of a long-term contract for service with the incumbent utility, since voltage support is one of the key services that the incumbent must provide to keep the system operational. Contracts for ancillary services such as voltage support, are typically provided on a lump sum, annual basis.

Lastly, the provisions of FERC Open Access Tariffs require utilities to consider the potential for deferrals as an incentive for private investment and innovation for the development of transmission lines. Essentially, deferrals relate to the potential for a generation project to replace or avoid (in the medium to long term) the costs related to a transmission project. Thus, a less costly project may claim and negotiate benefits that relate directly to the avoided cost of a previously proposed transmission line. Deferrals must be negotiated with incumbent utilities, with guidelines provided by FERC. Order 2003-A requires utilities to negotiate the benefits paid for a less expensive substitute than the original project, at 75 percent of the cost of the more expensive facility (BPA, 2004b).

[27] Service contracts generally follow open season bids or bi-lateral contract negotiations.

5.2 Financial Criteria for Comparison of Costs and Benefits

It is important to consider both the costs and benefits of the three transmission projects for a financial comparison of the three transmission projects. Accordingly, this section discusses the costs and benefits for several financial criteria. Since the comparison is carried out for three projects, for some criteria it is not possible to subtract the benefits for a single project but rather the cost must be added to the other two projects. The comparison focuses on the selection of a single project that provides the least cost to increase transmission to Vancouver Island.

Table 15 contains a list of the probability distributions used for the financial comparison of the projects. Each of these parameters is defined and described in Sections 5.2.1 to 5.2.10. From Table 15, the triangular distribution was used most often to designate the minimum, most likely, and maximum values for the financial criteria. Repeated sampling of these distributions was carried out to calculate the total direct costs, total indirect costs/benefits, and thus the total costs for each project.

5.2.1 Project Development Costs

The project development cost includes all the conceptual studies, feasibility studies, CPCN and environmental permitting, as well as planning and budgeting for the EPC contract negotiations. For the VITR Project, these incurred costs are presently $10 million, and thus are not included in the table. They are, however, added to 75 percent of the total direct cost for VITR to determine the price for JDF, as discussed in Section 5.2.2. For the VIC Proejct, the development work has yet to be done, and thus the costs are estimated as a triangular distribution with minimum and maximum values of $20 and $26 million, with a most likely value of $24.5 million (Sea Breeze, 2005c). The development costs for the JDF Project are presently $4 million, and constitute a sunk cost that is not appropriate to the comparison of project costs.

Table 15: Probability Distributions for Input Parameters for Project Comparison

Item	VITR	VIC	JDF
Direct Ratepayer Costs (all costs in $ millions)			
Project Development	$0 (sunk cost)	Triangular (20, 24.5, 26); (Note 1)	(not applicable)
Project Implementation (Note 2)	Triangular (191.5, 208, 235)	Triangular (340, 346, 361)	(not applicable)
Project Contingency	Triangular (8, 16.5, 40)	Triangular (340, 346, 361)	(not applicable)
Capital Costs	Sum of above	Sum of above	(not applicable)
Direct O&M Costs for Project	Uniform (1.6, 3.3)	Uniform (12.8, 13.7)	(not applicable)
PV of Taxes Paid by Project	27.5	Uniform (27.5, 40)	(not applicable)
Total Direct Costs	Sum of O&M, Taxes, Cap Cost	Sum of O&M, Taxes, Cap Cost	75% of VITR Capital Cost (Note 3)
Indirect Ratepayer Costs / Benefits (all costs / benfits in $ millions)			
Seismic risk costs	Triangular (0.0, 2.5, 6.5)	0.0	0.0
VI voltage stability support	Triangular (2.5, 5.9, 11.8)	0.0	0.0
LM voltage stability support	30.0	0.0	30.0
Existing O&M costs avoided	0.0	0.0	0.0
Power Losses (relative to VITR)	0.0	Triangular (30, 36, 39)	Triangular (32, 37.5, 40)
Advancement of VITR Phase 2	(not applicable)	12.0	12.0
US transmission costs & losses	0.0	0.0	See Section 5.2.10
Total Indirect Costs/Benefits	Sum of all costs / benefits above	Sum of all costs / benefits above	Sum of all costs / benefits above
TOTAL COSTS ($thousands)	Sum of Direct and Indirect Costs	Sum of Direct and Indirect Costs	Sum of Direct and Indirect Costs

Notes:

1. *See Appendix A for a discussion of probability distributions and examples of triangular and uniform distributions.*
2. *Implementation costs include Interest During Construction, Insurance, Communications and Control, Properties, Overhead, and Profit.*
3. *See Section 5.2.2 for a discussion of JDF Costs calculated as 75% of the total direct costs of VITR..*

5.2.2 Project Implementation and Contingency Costs

Project implementation includes the detailed design and construction of the project, which would include the manufacturing and supply of the all the cable and electrical components, as well as installation. Contingency costs include allowances for limited cost overruns on the projects.

The VITR Implementation cost is highly dependent on the price of the marine cable tender, which is about 55 percent of the cost of the project. During the Hearing, BCTC provided P50 cost estimates for the implementation of the both the overhead option and the underground options for the project in South Delta. The P50 estimate was $220.5 million for the overhead option through South Delta, and $233 million for the underground option. The overhead option was used in the financial analysis, with a triangular distribution (Table 15). This range in costs represents the lower bound of costs reported by BCTC and the P90 costs provided to the BCUC in response to information requests. The contingency for the VITR Project was estimated as $16.5 million, and a triangular distribution was used to estimate the amount of this contingency that would be used during construction. Figure 16 shows the probability distribution functions for the three projects that were used for comparison purposes.

The VIC Project was proposed as a design-build project, with development by Sea Breeze or BCTC with an EPC contract with ABB, Inc. Cost estimates provided by Sea Breeze for the project, based on estimates provided by ABB and development experience on previous projects, resulted in a P50 cost estimate of $346 million, and a P90 estimate of $361 million (Sea Breeze, 2006b). The triangular distribution for the VIC implementation costs reflects this range of costs (Figure 16). The contingency for the VIC Project was disproportionately lower compared to the VITR Project, given that the VIC Project would be built using an all-inclusive, fixed-price EPC contract to ABB.

As the JDF Project was outside the jurisdiction of the BCUC, the costs for the project were not subject to the same level of examination as the costs for VITR or VIC. Hence, during the Proceeding, Sea Breeze put forward an offer for the entire to South to North capacity on the JDF Cable that would be used by BCTC for reliability and BC Hydro to meet customer demands on Vancouver Island or for import. Thus, the total direct cost for the JDF Project is calculated as 75 percent of the total direct cost as shown in Figure 16 (excluding VITR operations and maintenance, and VITR taxes). As put forward by Sea Breeze, the offer for south-to-north service on VITR includes all development, implementation, and contingency costs, as well as operations, maintenance, and taxes. Note that Sea Breeze would retain the rights to charge tolls for transmission in the north-to-south direction, as well as ancillary services (voltage stability, blackstart capability, etc.) that are included with the HVDC Light® converter station technology. Any deferral payments or credits on the BPA system would also accrue to Sea Breeze (Sea Breeze, 2006b).

5.2.3 Project Operations and Maintenance Costs

As conventional high voltage alternating current (HVAC) technology, the operations and maintenance costs for the VITR Project are well understood. BCTC (2006a) submitted these costs would be $0.22 million per year, or an NPV of $1.6 million over the life of the project. Sea Breeze estimated higher costs for the system at $3.3 million (Sea Breeze, 2005c). A uniform probability distribution was used with these estimates as endpoints.

Similarly, for VIC, Sea Breeze submitted the operations and maintenance costs of $0.9 million per year, or $13.7 million over the project lifetime, based on information from ABB. BCTC provided a cost estimate of $12.8 million for the VIC Project. As with the VITR Project, a uniform probability distribution function was used for the analyses (Table 15).

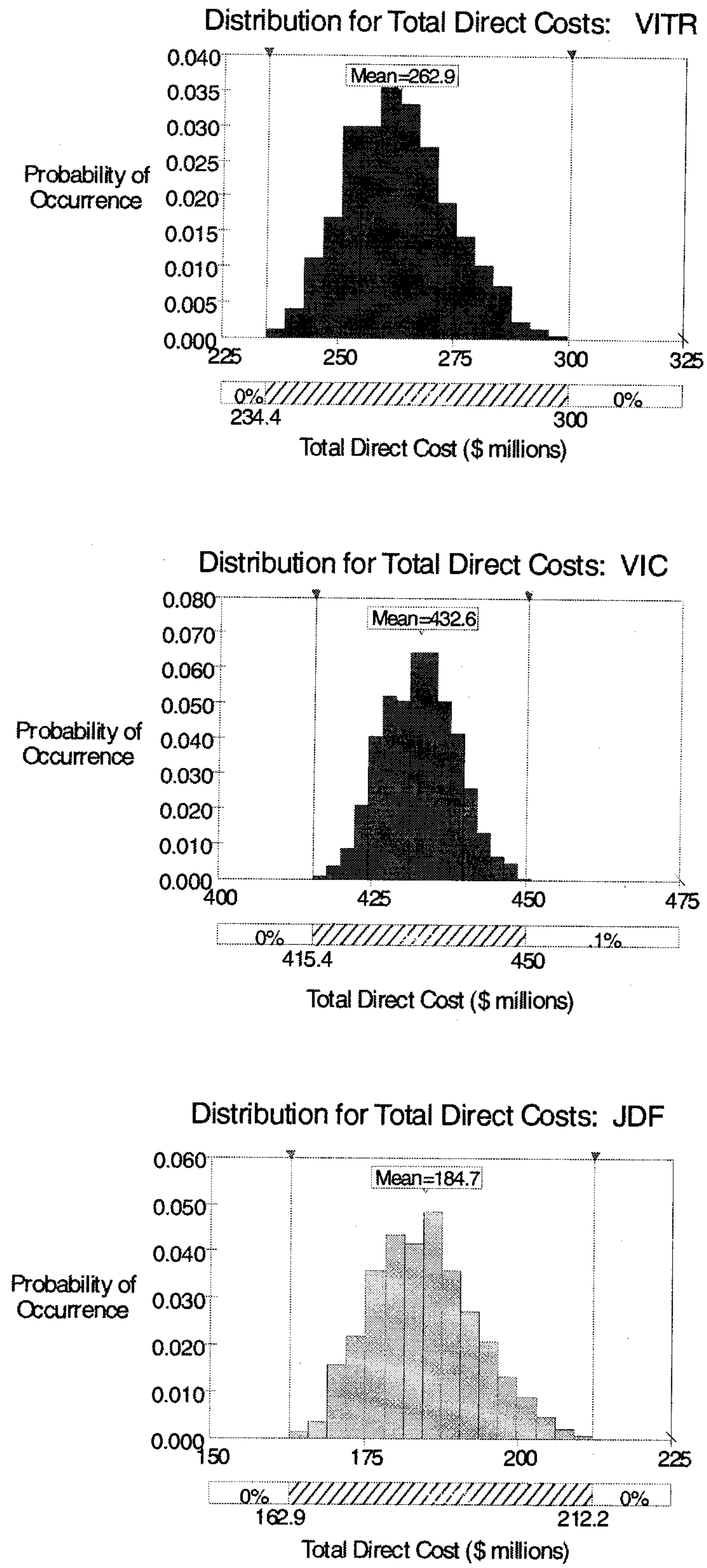


Figure 16: Histograms showing total direct costs for VITR, VIC, and JDF Projects

5.2.4 Project Taxes

As a crown corporation, BCTC and BC Hydro pay limited taxes related to transmission facilities. Specifically, BCTC is assessed a rate for school taxes at 1.49 percent, and applied revenue grants for a total of $27.5 million for the VITR Project. In terms of the VIC Project, the taxes paid by Sea Breeze or BCTC would be subject to the classification of the converter stations, and could vary from $27.5 million to as much as $40 million. A uniform probability distribution function was used for the VIC Project. For the JDF Project, any taxes that are paid would be included in the 75 percent cost of the VITR Project.

5.2.5 Seismic Risk Costs

Considerable information regarding the seismic conditions for the three projects was put forward during the evaluation of the three projects. As it is located in seismically unstable soils, the substation in Delta for the VITR Project was highlighted as a potential liability in the event of a large earthquake. The marine route of the VITR Project also passes through an area of steep seabed slopes, and very large submarine landslides have occurred in the general area. BCTC indicates that the time to repair the substation in the event of earthquake damage is relatively short (less than 72 hours), whereas the time to repair the submarine cable could take three months depending on the availability of a cable laying ship that has the required capabilities for repair. Using the value of $50 MWh for bridging costs, and assuming the marine cable could up to three months to repair, the risk cost for the loss of the VITR marine line varies between zero and $6.5 million (assuming a 3 percent likelihood of earthquake occurrence during the lifetime of the project, as determined by BCTC consultants). Note that these costs would not be applicable if another transmission line is able to supply Vancouver Island while the VITR marine cable is under repair.

The VIC Project does not cross any landslide prone areas, and very few areas prone to liquefaction. Thus, the seismic risk cost is estimated as zero for this analysis. Similarly, the JDF Project is not exposed to seismic risks due to the lack of landslide areas and favourable soil conditions.

5.2.6 Voltage Support Costs

Given the lengths of the existing transmission system to Vancouver Island, voltage support is required to maintain frequency and voltage levels. This is accomplished through the use of phase shifting transformers (synchronous condensers) at the substation, which use electricity to modulate the frequency of the grid in the area. The cost to operate these is estimated by BCTC as between $2.5 million and $11.8 million, with a most likely value of $5.9 million. The difference relates to the number of transformers that can be eliminated if either the VIC or JDF projects is constructed.

The HVDC Light® converter stations for either the VIC or JDF Project would provide voltage support to the Vancouver Island transmission system. Accordingly, no costs are attributed to these projects for the comparison.

The Lower Mainland also has a requirement for voltage support, given the long transmission distance from the dams in the Peace River area to the Lower Mainland. Given the existing transmission system and the requirements for voltage support, a natural gas generation station in Port Moody (Burrard Thermal Station) is used to generate electricity to stabilize the grid, or electricity is imported from the US (whichever is more economical). BCTC estimates that these costs are about $30 million over the expected lifetime of the VITR Project.

The HVDC Light® converter station for the VIC Project would eliminate the need for operation of Burrard Thermal in synchronous condenser mode and result in savings of

$30 million. The JDF Project, since the converter station is not located in the Lower Mainland, would not reduce the requirement for voltage support.

5.2.7 Existing HVDC System Operations and Maintenance

With the derating of the existing HVDC Light® system, it can no longer be depended upon for reliable transmission service. However, given that the construction of the VITR Project alone does not provide the necessary standard of reliability, the existing HVDC line could be necessary in the event of an emergency (BCUC, 2006d). Thus, it is not possible to eliminate the operations and maintenance costs of this facility during the lifetime of the project.

5.2.8 Power Losses

The conversion of electricity from HVAC to HVDC (and back again) results in transmission losses. For the distances required in the three projects under consideration, the AC transmission losses are less than the conversion to DC current. Thus, the losses for comparison are estimated as relative to the VITR Project, and applicable to the VIC and JDF Projects. Based on information provided by BCTC and Sea Breeze, the losses are estimated as between $30 million and $40 million, and triangular probability distribution functions are appropriate (see Table 15 above).

5.2.9 Advancement of VITR Phase 2

Both the VIC and JDF Projects operate at 540MW, whereas the VITR Project operates at 600MW. BCTC, in its planning studies, indicates that a second phase for VITR will likely be necessary before 2017. Given the growth in electrical demand on Vancouver Island, the difference of 40MW will indicate that the second phase of VITR will be needed one or perhaps two years sooner if either VIC or JDF is built. Thus, given this requirement for another large capital project sooner than planned, an estimated cost of $12 million must be added to the VIC and JDF Projects.

5.2.10 US Transmission Costs and Losses

For the JDF Project, the issue of reliable generation and transmission to Port Angeles was the subject of considerable discussion at the BCUC Proceedings. BCTC indicated that firm transmission rights on the BPA system to move power to the south end of the JDF facility in Port Angeles would cost approximately $10.2 million per year, and the expected losses on the system would be $1.4 million per year, for a NPV of $152 million. This estimate is based on the transmission from Blaine on the mainland to Port Angeles on the Olympic Peninsula (BCTC, 2006). The implicit assumption in this estimate is that electricity generated from BC or power from the Canadian Entitlement would travel around Puget Sound to southern Vancouver Island. However, this is likely not possible due to congestion in the I-5 corridor north of Seattle. These costs represent the upper limit of the costs for transmission charges on the BPA transmission system.

However, there are a number of options to reduce these charges. These include actions that could be taken by Sea Breeze, such as including revenue from deferrals to offset transmission charges; actions that could be taken by BC Hydro and the BC Provincial Government, such as working with BPA to designate Port Angeles as a delivery point for the Canadian Entitlement power return, in which case the only cost would be the losses on the US transmission system. It is also important to note that in the US, transmission contracts are treated as property rights and can be sold or exchanged by transmission companies and power trading entities. Thus, while speculation is not allowed for the resale of such rights, a resale can be carried out to recover some costs. It is also possible that imports for Powerex (BC Hydro) could be diverted to Port Angeles, particularly if Port Angeles was designated as a hub for network transmission service[28]. As envisioned by Sea Breeze, the combination of using the Canadian Entitlement (or purchasing of generation) and designating Port Angeles as a delivery point would allow BCTC to rely on the Entitlement for reliability purposes for Vancouver Island.

Some upgrades are also required on the BPA system for the JDF Project to carry the full 540MW of transmission. A preliminary estimate of these costs is between $70 and $80 million. However, it is important to note that if these upgrades are paid by Sea Breeze, they receive transmission credits on the BPA system of equal value, which would allow Sea Breeze to schedule transmission through the BPA system. As with the firm transmission capacity that could be purchased by BCTC for transmission to Port Angeles, these transmission rights could be resold to another party and thus create a revenue stream for Sea Breeze.

5.3 Comparison of Project Costs for Reliability

Based on the financial criteria, costs, and probabilities discussed in Section 5.2 above, the costs for the projects were calculated on a probabilistic basis. Figure 17 contains the average costs that were calculated using the probability distributions in Table 15.

From the calculation of average total project costs, the VIC Project is the most expensive at an average total cost of $479.7 million. The JDF Project was the second most expensive, at a total cost of $413.3 million. Note of this cost, the charges for US transmission costs and losses amounts to 36 percent of the total direct and indirect costs. The least expensive is the VITR Project from BCTC, at $302.7 million. Thus, although the JDF Project has the lowest total direct cost, the indirect charges associated with US transmission service render it more expensive than the VITR Project.

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[28] A network hub is a regional electrical trading hub where generators, customers, and power traders can deliver (or take delivery of) power (BPA, 2006c).

Table 16: Summary Comparison of Project Costs for Vancouver Island Reliability

Item	VITR	VIC	JDF
Direct Ratepayer Costs (all costs in $thousands)			
Project Development	0.0	23.5	--
Project Implementation [1]	211.5	349.0	--
Project Contingency	21.5	13.2	--
Capital Costs	233.0	385.7	0.0
Direct O&M Costs for Project	2.5	13.3	--
PV of Taxes Paid by Project	27.5	33.8	--
Total Direct Costs	263.0	432.7	197.2 [2]
Indirect Ratepayer Costs / Benefits (all costs in $thousands)			
Seismic risk costs	3.0	0.0	0.0
VI voltage stability support	6.7	0.0	0.0
LM voltage stability support	30.0	0.0	30.0
Power Losses (Compared to VITR)	0.0	35.0	36.5
Advancement of VITR Phase 2	0.0	12.0	12.0
US transmission costs	0.0	0.0	150.0
Total Indirect Costs/Benefits	39.7	47.0	228.5
TOTAL COSTS ($thousands)	302.7	479.7	413.3 [3]

Notes:
1. Implementation costs include Interest During Construction, Insurance, Communications and Control, Properties, Overhead, and Profit.
2. JDF Costs calculated as 75% of the total direct costs as put forward by Sea Breeze in its submission to the British Columbia Utilities Commission.
3. These costs assume that the transmission rights would not be resold, or that the delivery point for the Canadian Entitlement cannot be moved from Blaine on to Port Angeles. See Section 5.2.10.

A comparison of the VITR and JDF Project costs indicates that a consideration of probability shows that VITR is less expensive than JDF in all cases that were simulated (Figure 17). Note that if the US transmission charges were eliminated through the movement of the delivery point for the Canadian Entitlement to Port Angeles, the JDF Project would be less expensive than the VITR Project (Figure 18). These results indicate that the cost could vary from $28.4 million to as much as $51.8 million. The mean of the values calculated is $39.4 million, and the distribution approximates a triangular distribution.

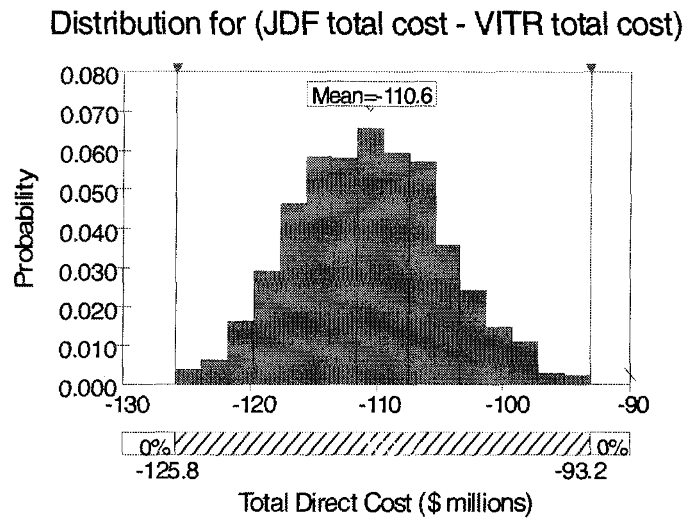
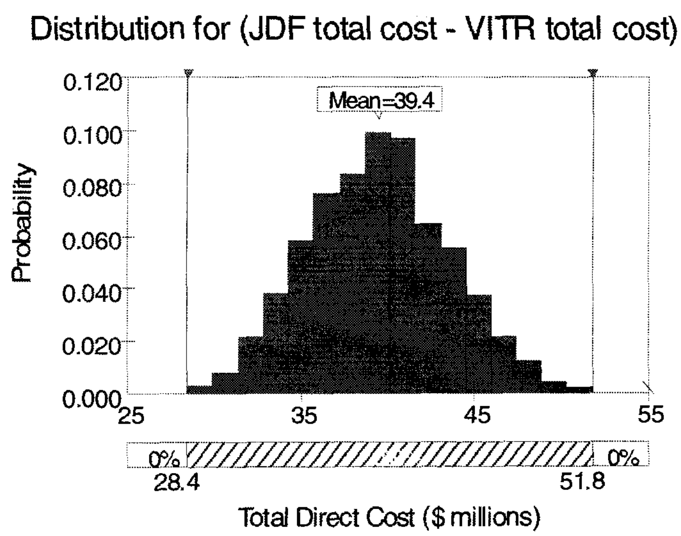


Figure 17: Comparison of the difference VITR and JDF total project costs



Note: Assumes US transmission charges against the JDF Project of $150 million.

Figure 18: Comparison of the difference between JDF and VITR total costs (assuming no US transmission charges)

5.4 Comparison of Project Costs for Reliability and Export

The comparison of project costs points to the selection of the VITR Project to establish transmission reliability for Vancouver Island. However, what if the objective of the project evaluation was to not only meet the requirements for reliability, but also the implications for BC Hydro exports? This section considers the construction of both the VITR and JDF Projects, and the associated revenues from transmission tariffs and and increased exports. Table 17 provides the input data for the total direct and indirect costs and lists the additional factors that must be included as a consideration of import and export. Section 5.4.1 discusses the reliability benefits of having the two projects and Section 5.4.2 discusses the benefits of import and export.

5.4.1 Total Costs for VITR and JDF

The total costs for the VITR and JDF Projects together were calculated as the sum of the simulated results for the cost of VITR and 75 percent of each result was added (to represent the cost of JDF). Figure 19 shows the distribution of the total costs for the analysis.

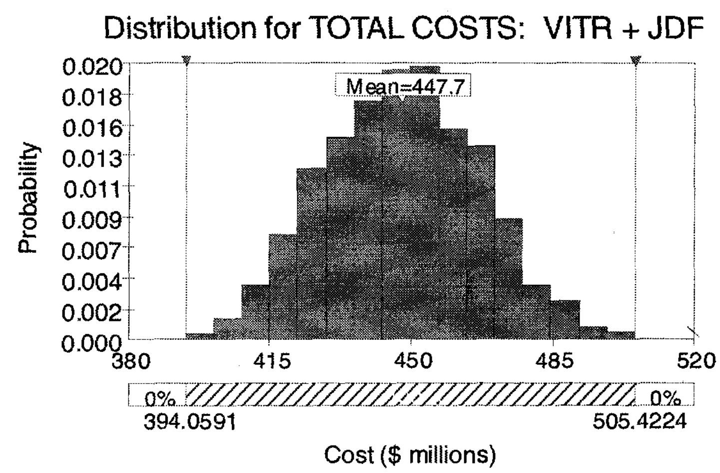


Figure 19: Total costs for construction of both VITR and JDF Projects

5.4.1.1 Advancement of VITR Phase 2

The addition of the JDF Project to the transmission system once VITR is constructed will preclude the need for the construction of the second phase of the VITR Project (VITR2). Given that the second phase would involve stringing new conductors on the poles installed for VITR, there are negligible costs associated with the terrestrial phase of VITR2. However, given that the project will require the supply and installation of a new marine cable, these costs would not be following the construction of the JDF Project. The cost for the cable tender in Spring 2006 was \$139 million, and the estimated date for construction of VITR2 is 2017 (BCTC, 2005). Thus, assuming the cost of the cable in 2017 to be \$139 million in nominal dollars, the NPV of the avoided capital cost for the marine cable is \$79 million in 2006. Assuming the same contingency for the current cable, this has a NPV of \$7.9 million in 2006. Thus, the benefit due to the avoided cost of the VITR2 marine cable if JDF is constructed was modelled as a triangular probability distribution function, with a minimum value of \$71.4 million, a most likely value of \$79 million, and a maximum value of \$86.6 million.

Table 17: Average project costs for comparison of both VITR and JDF for reliability and export

Item	VITR + JDF	Section Reference
Direct Ratepayer Costs ($ millions)		
VITR Project Development	0.0	No costs; see Section 5.2.1
VITR Project Implementation	211.5	VITR Cost; see Section 5.2.2
VITR Project Contingency	21.5	VITR Cost; see Section 5.2.2
Capital Costs	233.0	
Direct O&M Costs for Project	2.5	VITR Cost; see Section 5.2.3
PV of Taxes Paid by Project	27.5	VITR Cost; see Section 5.2.4
Total Direct Costs	263.0	VITR Cost; see Figure 16
JDF Total Direct Cost	184.8	JDF Cost; see Figure 16
Total Direct Cost for Both Projects	447.7	See Section 5.4.1 below
Indirect Ratepayer Costs / Benefits ($ millions)		
Seismic risk costs	0.00	See Section 5.2.5 above
VI voltage stability support	6.73	See Section 5.2.6 above
LM voltage stability support	0.00	See Section 5.2.6 above
Existing HVDC O&M costs avoided	(20.00)	Triangular (-15, -20, -25)
Power Losses (Compared to VITR)	0.00	No cost or benefit with VITR + JDF
Advancement of VITR Phase 2	(79.00)	See Section
US transmission costs and losses	0.00	See Section 5.2.10 above
Total Indirect Costs/Benefits	(92.27)	
TOTAL COSTS / BENEFITS	355.43	

Notes:
1. Implementation costs include Interest During Construction, Insurance, Communications and Control, Properties, Overhead, and Profit.
2. JDF Costs calculated as 75% of the total direct costs as put forward by Sea Breeze in its submission to the British Columbia Utilities Commission.

5.4.2 Benefits of Import and Export

The construction of the JDF Project for increased trade will increase the electrical flow on the BC transmission system and thus the transmission tariff revenues for BCTC. The additional capacity for export will also allow Powerex, the trading marketing arm of BC Hydro, to increase its revenues through increased arbitrage opportunities. The use of the JDF Project for import and export will also reduce the congestion in the I-5 corridor.

5.4.2.1 OATT and Trade Revenues

The use of the JDF Project for export would increase the flow of electricity for export on the BCTC system, and thus increase the toll revenue due to BCTC under the Open Access Transmission Tariff (OATT). Under the provisions of the OATT Agreement, transmission customers that use the BCTC system for transmission of electricity (including BC Hydro) pay a tariff based on the amount of power that is transmitted. An exact prediction of the increased use is not possible. However, estimates were provided by Sea Breeze during testimony before the BCUC (BCUC, 2006b). Specifically, the construction of the JDF Project would add 20 percent to the export capability for BC, and the three scenarios considering 15 percent, 20 percent and 25 percent firm transmission on the JDF Project were put forward to quantify the implications, based on the transmission capacity of 540MW in each direction. If the entire 540MW capacity was used for firm transmission, the OATT revenues would be $54 million per year, whereas contracts for firm transmission for partial capacity of the line can be supplemented by short-term contracts. The value of short-term contracts is generally less than for long-term firm contracts.

The minimum use of the JDF line for firm transmission would be 15 percent, corresponding to $8.2 million. Additionally, the remaining capacity on the line would be available for other types of transmission services, such as short-term firm transmission and non-firm transmission. Given that these rates are approximately half the rate for firm transmission service, the additional revenue would be $9.3 million, for a total of $17.5 million per year.

The most likely use of the JDF line for firm transmission would be 25 percent of the capacity for firm transmission. This corresponds to BCTC OATT revenues of $13.7 and $6.83 million per year for long-term firm and short-term services, respectively. Thus, the most likely increase in OATT revenues totals $20.53 million per year.

The maximum likely use of the JDF line for firm transmission service is 35 percent of the line to be contracted for long-term firm services. This would result in revenues from firm transmission service of $19.15 million per year and short-term / non-firm service revenues of $4.26 million per year. The total for the maximum likely OATT revenues to BCTC from the use of the JDF line is thus $23.41 million per year. Table 18 outlines the annual and net present values for the increase in revenues due to BCTC from the increased transmission through the JDF project once it is operational.

The 20 percent increase transmission capacity will also allow for increased revenue from electricity exports. The export revenue recently reported by BC Hydro ranges from $256 million per year ending March 31, 2005 (BC Hydro, 2005), and $158 million for Fiscal Year 2004-2005. Projections for trade revenue are expected to increase through Fiscal Year 2009 (BC Hydro, 2005). In the recent Integrated Electricity Plan, BC Hydro indicated that the spot market would continue to be "volatile", and such price fluctuations presented increased opportunities for arbitrage. In response to Information Requests, BC Hydro also stated that the reliance of the Canadian Entitlement and the spot market for meeting the Provincial demand for electricity would reduce the flexibility of BC Hydro to arbitrage and generate revenue on the spot market (BC Hydro, 2006b).

Based on information provided to the BCUC, a conservative estimate of the increased revenues for BC Hydro from exports is 10 percent of $200 million per year, or $20 million per year. Taking 10 percent as the most likely estimate, the minimum estimate is a 5 percent increase in trade revenue or $10 million per year, and the maximum is a 15 percent increase in trade revenue for $30 million per year. Table 18 outlines the annual and net present values for the increase in trade revenues.

It is important to consider that the OATT revenues and the increased revenues from trade are correlated. This is due to increased transmission generating both OATT tariff charges and export revenue, and adding the two together is appropriate to the calculation of benefits.

Table 18: Increased BCTC OATT and BC Hydro trade revenues (BCUC, 2006c).

Item	Annual	NPV Total[1]
Increase in BCTC OATT revenues (all costs in $millions)		
Minimum	17.5	261.6
Most likely	20.5	306.5
Maximum	23.4	349.8
Increase in BC Hydro trade revenues (all costs in $millions)		
Minimum	10	149.5
Most likely	20	299.0
Maximum	30	448.5
Increase in OATT and trade revenues (all costs in $millions)		
Minimum	--	414.0
Most likely	--	610.0
Maximum	--	804.0

Notes:
1. NPV costs calculated based on a revenue stream (project life) of 40 years, and a discount rate of 6%.
2. Increases in BCTC OATT revenues and BC Hydro trade revenues are based on firm transmission on the JDF Project of 15%, 20%, and 25% to establish the low, probable, and high values for probability modelling.

5.4.2.2 Decrease in Congestion along the I-5 Corridor

The use of JDF for trade will also avoid the use of the I-5 corridor, and reduce the number of instances when exports or imports from Powerex are curtailed on the BPA system. For example, transmission of Powerex deliveries were curtailed on 300 days in the year ending April 2005, and the total volume of these curtailments were more than 25 percent of the total amount of trade that Powerex carried out on or through the BPA system (BPA, 2005). While not all of these curtailments can be directly attributed to the I-5 corridor, it appears that BPA curtailments significantly affect the ability of Powerex to arbitrage in Pacific Northwest markets.

The local municipalities and BPA would also benefit from the use of the JDF line for import and export. Under the PSANI Agreement, the local municipalities were curtailed during bulk transmission of the Canadian Entitlement north to BC, and thus many municipalities would likely require alternate supply through demand side management or operation of natural gas generation facilities (BPA, 2006b).

Thus, there is a strong incentive to avoid congestion on the I-5 corridor, either through the construction of new transmission facilities or through demand-side management to reduce the required capacity on the transmission system. BPA has recently constructed the nine-mile Kangley–Echo Lake 500kV transmission line in eastern Puget Sound area as the first stage to relieve this congestion, at a cost of $85 million (BPA, 2002). The remainder is a 32-mile, 500kV transmission line that would connect Echo Lake with Monroe, east of Seattle (BPA, 2002). This project would add 600MW of south-to-north capacity in the area, and 850MW north-to-south capacity. It would also increase the load-serving capability for municipalities in the area. At an estimated cost of $90 million (2001) dollars, the cost recovery as part of BPA's rates is expected to range from 10 to 16 years. This project is currently on hold while BPA investigates demand-side management in the area (BPA, 2004) and BPA has recently issued a draft long-term policy that discusses a reduced role in supplying power and transmission infrastructure in the Pacific Northwest (BPA, 2006b).

While it is not possible to quantify the benefit that the JDF Project would provide in terms of reducing congestion, it would likely defer the need for the BPA Monroe-Echo Lake transmission upgrade and thus be eligible for a deferral credit in terms of transmission rights on the BPA system. This deferral credit is not included the calculation of benefits to ratepayers/taxpayers in BC, since it accrues to Sea Breeze and is not included as part of the proposal to BCTC and BC Hydro (BCUC, 2006c).

5.4.2.3 Profit to Ratepayer / Taxpayer

Based on the total cost of both the VITR and the JDF Projects, the total profit to the ratepayer and the taxpayer was determined by examining the total costs of both projects along with the revenues from increased transmission and exports. The decrease in congestion costs to BC Hydro that are associated with a transmission path that avoids the I-5 corridor are conservatively estimated as zero, as any the benefits are difficult to calculate.

Table 19: Average costs, benefits, and profit to Ratepayer / Taxpayer with both VITR and JDF

TOTAL COSTS for VITR/JDF	355.43
OATT and Trade REVENUES	609.33
PROFIT TO BC RATEPAYER / TAXPAYER	**253.90**

An examination of the simulation results shows that the likelihood of a positive NPV for the profit to ratepayers and taxpayers is indeed significant as shown in Figure 20. The values range from $42.8 to $451.5 million, with a mean of $253.9 million. The distribution is approximately triangular, indicative of the triangular distributions for OATT/trade revenues and the nearly triangular distribution for the total cost of the projects.

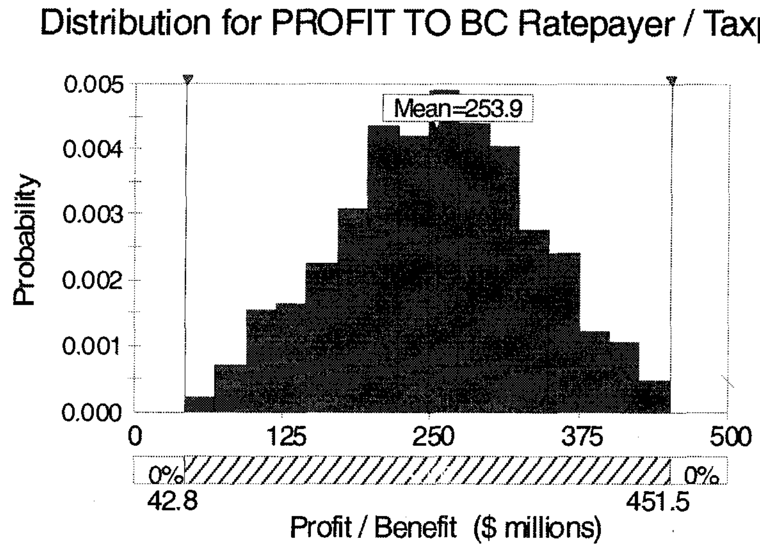


Figure 20: Distribution of simulated profit to ratepayer / taxpayer with both VITR and JDF

5.5 Summary

Probability was used to incorporate uncertainty in the cost estimates for the VITR, VIC, and JDF Projects. Given information that was presented at the BCUC and the NEB, probability distribution estimates for project development, implementation, operation, and indirect costs/benefits were developed for each project. Repeated calculations were carried out to evaluate the total costs, summing the direct and indirect costs, for each project.

A comparison of the financial criteria for the VITR, VIC, and JDF Projects indicates that the VITR Proposal is the least expensive proposal for establishing reliability to Vancouver Island. This comparison is based on the assumption that the NPV for the transmission charges for the BPA system to establish reliability are $150 million. These charges could be reduced through the resale of the transmission rights on the US system, or by adding Port Angeles as a delivery point for the return of the Canadian Entitlement to BC.

A comparison of the total benefits for constructing both the VITR and JDF Projects was also carried out. Based on estimates of BCTC transmission tariff revenue and increased trade revenue that would likely result from the construction of the JDF Project, the benefit (or profit) to the ratepayers and taxpayers of BC is significant, and likely to vary between $42.8 million and $451.5 million. This dramatic change from the result of comparing the projects individually is due to the construction of the VITR Project providing reliability to Vancouver Island, while the JDF Project provides the opportunity to generate revenue through arbitrage. With the construction of VITR, the charges for transmission through the US system are included in the arbitrage carried out by Powerex. This analysis shows that the VITR Project and the JDF Project are highly complementary in that constructing both projects provides enhanced reliability and significant revenues to the BC ratepayer / taxpayer.

6 DISCUSSION AND CONCLUSIONS

A comparison of the technical, regulatory, and financial aspects of three alternatives for transmission projects to Vancouver Island demonstrates the importance of considering the regional transmission context as well as non-financial and financial criteria for the selection of a project.

It is important to note that the British Columbia Utilities Commission, in its July 7, 2006 Decision regarding the VITR Project, granted a Certificate of Public Convenience and Necessity to BCTC for the construction of the VITR Project. The BCUC did not request BCTC / BC Hydro to negotiate with Sea Breeze regarding the contracting of the entire South-to-North capacity.

6.1 Non-Financial Criteria

Non-financial criteria are important to determine the feasibility of the project and to evaluate the socio-economic impacts. Four criteria - public health, accidents and malfunctions, operational reliability, and project schedule – are important for the viability of the transmission projects. These criteria are essentially threshold variables indicative of existing standards.

The VITR, VIC, and JDF Projects are all likely to meet the thresholds for public safety as well as accidents and malfunctions. The one important difference in the projects is a result of the technology, with the VITR Project proposing to use older, alternating current technology. Transmission lines are often the target of public opposition, given that they are normally overhead lines and nearby residents are concerned about health impacts and adverse effects on property values. Such interests, especially when organized, can delay or block projects. The VIC Project has the support of many municipalities it crosses, and the JDF Project has the support of all the municipalities. This support is due in large part to the flexible, underground HVDC Light® cables which require only 10 percent of the right-of-way width of overhead lines. Given the response of the municipalities to the VIC and JDF Project proposals, it was clear that they saw an opportunity for collaboration rather than a potential problem.

The difference between the projects was more pronounced related to the operational reliability and the project schedule. For operational reliability, the potential damage from a seismic event to the VITR Project, particularly the marine cables, strongly implies that the operational reliability is less than the VIC or JDF Projects. However, the difference is less pronounced for the VIC Project due to the longer route. Both the VIC and JDF Projects have a slightly more frequent maintenance schedule, and thus the seismic risk exposure is somewhat balanced by the certain outages for maintenance. Following an earthquake, however, the economic losses to Vancouver Island due to the estimated 90 days to repair the cable would be considerable and must factor into the analysis. It should also be noted that poor historical performance of the existing 500kV transmission system to Vancouver Island suggests that more than one project may be required to definitively provide security of supply to Vancouver Island (BCUC, 2006c).

In terms of project schedule, the acquisition of property rights for the VITR Project would likely delay the in-service date to mid-2009. Alternatively, delays in the manufacture or installation of the marine cable, or US permitting, would also adversely affect the project schedule and render an in-service date sometime in 2008 not possible. The VIC Project would also likely be in service during mid- to late 2009, depending on the timeline for Sea Breeze to reach agreement with BCTC on the project team. The JDF Project, by virtue of its earlier start in the regulatory process, would likely meet an in-service date of winter, 2008. However, this would require contracts for service from BCTC or BC Hydro for transmission service. In this case, a contract between Sea Breeze and BCTC/BC Hydro for South-to-North service on the JDF

Project would likely act as catalyst for additional contracts for service and support for the project[29].

6.2 Financial Criteria

A comparison of the three projects for meeting the reliability demands of Vancouver Island demonstrates that the VITR Project is the least costly alternative. This is due to the higher costs of the VIC Project and the US transmission charges that could be needed for the JDF Project to provide firm reliability to Vancouver Island before winter, 2008. This result hinges on the return of the Canadian Entitlement to BC, and continued reliance on the existing 500kV transmission system that currently meets most of Vancouver Island's needs.

BC Hydro, in the Integrated Electricity Plan and Long-Term Acquisition Plan, considered the use of the Canadian Entitlement as a resource for meeting the energy needs of the Province. Given that these are available now and with the rapid growth in the BC economy, there is increasing pressure to meet domestic demand using the Entitlement. However, BC Hydro cites the uncertain availability of the Entitlement, given that transmission constraints do not always allow them to be returned on demand to the Province. BC Hydro also indicates that the use of the Entitlement to meet domestic power on a continuous basis reduces the flexibility for Powerex to arbitrage. Despite this reluctance, the Canadian Entitlement appears prominently in most resource portfolios that BC Hydro describes in the Integrated Electricity Plan (BC Hydro, 2006a). The information regarding the Canadian Entitlement put forward by BC Hydro suggest that BC Hydro would prefer to have the flexibility of being able to use the Canadian Entitlement in BC, but not at the lost opportunity of developing new generation in the Province. Note that low water

[29] The revenues from such a contract from BCTC / BC Hydro would send a strong signal to other utilities and power companies that the JDF Project was acceptable, with BCTC / BC Hydro acting as an 'anchor tenant' (BCUC, 2006c).

years, combined with high natural gas prices, would increase the volatility of electricity prices and favour the cost-effective return of the Canadian Entitlement to BC for domestic use.

In terms of import and export, an analysis of the costs and benefits of constructing both the VITR and JDF Projects are such that significant benefits can likely be realized with the addition of the JDF Project to the Vancouver Island transmission system along with the VITR Project. This is a direct result of the VITR Project eliminating the need to purchase firm US transmission rights to supply JDF, as the VITR Project supplies reliability to Vancouver Island. In addition, the construction of JDF essentially replaces the second phase of the VITR – and thus the cost of a second marine cable is avoided with the addition of the JDF Project.

The benefits of the JDF Project relate to both the increase capacity for electricity trade and reduce congestion in the I-5 corridor. The capacity of the existing transmission system often limits the rate of export by Powerex (ZE PowerGroup, 2005). This is due to the capacity of the existing intertie and transmission constraints south of the BC-US border. The problems with congestion are exemplified by the PSANI Agreement, a remedial action scheme developed by BPA to work with the municipalities in eastern Puget Sound to return the Canadian Entitlement. BPA also discusses the congestion in the I-5 corridor in its recent report (BPA, 2006a), in addition to earlier documents which reflect the concerns of Powerex regarding congestion on the BPA system (BPA, 2005). With over 25 percent of its trade affected by the constraints of the BPA system in the year ending April 2004, Powerex has a vested interest in obtaining more secure transmission rights within and through the BPA system, as indicated in their comments on BPA's transmission system operation limits (BPA, 2005). The US Department of Energy, in a recent report, specifically highlighted the transmission network in the Seattle area as one of four areas in the nation where transmission congestion was critical (DOE, 2006).

The problem of exporting into and through the BPA system is likely to become more acute with the addition of new generation and transmission facilities in BC. The planned generation additions to Mica and Revelstoke dams will generate 1860 MW more electricity (BC Hydro, 2006a), and over 1500 MW was obtained in recent contracts with independent power producers (BC Hydro, 2006c). A new transmission line is proposed to link the BC Interior with the Lower Mainland, increasing the amount of electricity available for export. The JDF Project will allow BC Hydro to increase the rate of export and thus maximize its arbitrage revenues.

6.3 Conclusions

Clearly the electricity markets are changing in the Pacific Northwest. Regulatory reform and new transmission projects are promoting more competitive wholesale markets for electricity. Shifting demand patterns, constraints on dam operations, and continual transmission system upgrades are changing the transmission patterns. The requirement for transmission reliability will result in new projects that will reduce transmission constraints between regional markets. While BC Hydro, with its large dams, was once in an enviable position to arbitrage electricity markets both in Alberta and the Pacific Northwest, the changes in the electricity markets are significantly reducing arbitrage opportunities.

The JDF Project provides BC Hydro with an opportunity to secure transmission paths on the BPA system, and increase access to export customers in the Pacific Northwest. The JDF Project would also allow for the return of the Canadian Entitlement to BC, directly to Vancouver Island which has limited potential for firm generation. The results of this study demonstrate the expected complementary benefits of the JDF Project in addition to the VITR Project would provide significant revenues to the Province.

The results of non-financial criteria indicate that there is a very significant chance that delays to the VITR Project through property issues or project implementation will result in considerable delays to the in-service date. The JDF Project is not exposed to the same risks, due to the efficacy of the NEB Process and the efficiencies of an EPC contract with ABB for the design, manufacture, supply, and installation of the HVDC Light® system. Given the complementary nature of the JDF and VITR Projects, and the very tight timeline for constructing new transmission to Vancouver Island, there appears to be considerable advantages to BCTC / BC Hydro in negotiating for the entire South-to-North capacity on the JDF Project and acting as an 'anchor tenant' to spur the construction of the project.

6.4 Further Study

The analysis and conclusions point to several items that merit additional study. The expected amount of increased electrical trade as a result of the construction of the Juan de Fuca Project is a set of assumption that must be studied in depth to better define the benefits to the Province of BC. Certainly the residual value of firm transmission rights that BC Hydro would acquire must also be considered in the US transmission costs for the JDF Project, as well as the negotiating with BPA for the return of some of the Canadian Entitlement to Port Angeles.

A study of the regional benefits of the JDF Project, including reducing congestion in the I-5 corridor, would also provide additional incentive for BPA and Puget Sound municipalities to support the JDF Project. Clearly, the impetus for such a study is contained in a spate of recent reviews of cross-border transmission and integrated markets (Canadian Electricity Association, 2006; Pierce et al, 2006). The policy initiatives from FERC have highlighted the importance of Regional Transmission Organizations to resolve such issues. While the BPA initiative for ColumbiaGrid (BPA, 2006a) may provide the nucleus for such an RTO, it is really the combined and sustained efforts of all utilities in the region is necessary to resolve issues of congestion and market integration.

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