

**Canada/Pacific Northwest to Northern California Electric
WECC Regional Planning Project
Economic Analysis Committee**

Benefit to Cost Ratio Screening Analysis

Final Report

October 23, 2007

Note: This report was prepared as part of the WECC regional planning process for the Canada/Pacific Northwest-Northern California Transmission Project solely for the purpose of an initial economic screening. Inputs into and results of this report are preliminary in nature, highly sensitive to assumptions selected, and are provided to be indicative to provide insight. Input assumptions were selected to test what-if situations and they do not necessary represent the view of the Economic Analysis Committee. More complete studies are needed to determine the project viability.

October 23, 2007

Summary

The Economic Analysis Committee (EAC) was charged to perform a screening analysis on the economic feasibility of a new electric transmission line between Canada/Pacific Northwest (C/PNW) and Northern California.

To perform the screening analysis, the EAC used the FEAST analytical tool¹ to quantify benefits and costs for a multitude of possible conditions and scenarios. These possibilities included: load and resource scenarios created by the Load and Resources Committee; conceptual transmission configurations identified by the Technical Analysis Committee; and a range of natural gas prices and possible capital costs and performance for new electric generation facilities.

The Economic Analysis Committee developed a reference set of inputs to the screening analysis. For key drivers such as natural gas price, greenhouse gas (GHG) adder, and capital cost for generation facilities, the reference set also includes ranges of plausible values. The Economic Analysis Committee also modified the FEAST screening tool to account for potential benefits in improvements to grid efficiency and opportunities for regional seasonal power exchange.

The EAC performed its work using a participatory stakeholder process. Wide participation in the Committee was sought. Committee members collaborated in the review and development of the reference set and range of input assumptions. Individual Committee members were encouraged to perform their own analysis, and enabled with the FEAST tool to do so. The Committee conducted its work through regular web-meetings and telephone conferences among its members.

The three key findings of the screening level economic analysis are:

- 1) The benefits of a C/PNW-Northern California Line appear greater than the costs under a variety of conditions. There are also scenarios with less than 1.0 benefit-to-cost ratio.
- 2) Economics of the C/PNW-Northern California Line are sensitive to the cost and utilization of the transmission line; and the capital costs, performance, availability and accessibility of renewable resources in the British Columbia, the Pacific Northwest and California.
- 3) Grid efficiency improvements and the opportunity for regional seasonal power exchange² may provide additional economic justifications. In-depth quantification of such benefits is beyond the scope of this screening analysis, but should be completed as the planning of C/PNW-Northern California Line proceeds forward.

¹ FEAST stands for Frontier Economic Analysis Screening tool. FEAST was developed for the Western Regional Transmission Expansion Partnership in determining the feasibility of constructing the Frontier Line. FEAST is a simple tool for sophisticated users. It focuses on incremental resources, not a complete supply stack, and facilitates quantification of regional cost differences. FEAST is a screening tool, and is not intended as a substitute for necessary, in-depth analysis using production costing and/or market simulation tools. The FEAST tool also promotes transparency and facilitates leveraging pre-existing work.

² A Canada/Pacific Northwest-Northern California line can create an opportunity for reliability firming and seasonal energy exchange to serve winter peak demand in British Columbia.

1. Introduction

On August 16, 2006, Pacific Gas and Electric Company (PG&E) initiated the Western Electricity Coordinating Council (WECC) Regional Planning Project Review³ of electric transmission alternatives to connect Canada and the Pacific Northwest to Northern California. Potential project alternatives would include both 500 and 765 kilovolt (kV) alternating current (AC) and high voltage direct current (HVDC) lines, via overhead or undersea routes. A Steering Team was subsequently formed, among other objectives, to guide the development of the Canada/Pacific Northwest-Northern California (C/PNW-NC) Transmission Line Project. The Steering Team is composed of Avista Corporation, British Columbia Transmission Corporation, Sierra Pacific Power Company, PacifiCorp, PG&E, and the Transmission Agency of Northern California (TANC).

The Steering Team for the C/PNW-NC WECC Regional Planning project is interested in determining the feasibility of constructing the C/PNW-NC Line. To this end, the Steering Team created three Committees⁴ to perform analyses for the feasibility study. This report discusses the work performed by the Economic Analysis Committee (EAC).

The EAC was charged with building on the work of the Loads and Resources Working Group and the Technical Analysis Committee to perform an economic analysis of the feasibility of the list of possible new transmission. The EAC focused its efforts on informing Steering Team decision-making about economic feasibility. The EAC strived to, using a screening analysis approach, identify possible conditions under which the C/PNW-NC Line would have (a) benefits substantially greater than costs; (b) benefits substantially less than costs; and (c) benefits roughly comparable to costs. The Economic Analysis Committee also strived to assess the sensitivity of benefits and costs to key assumptions.

To perform the screening analysis, the EAC used the FEAST analytical tool to quantify benefits and costs for a multitude of possible conditions and scenarios. These possibilities included: load and resource scenarios created by the Load and Resources Committee; conceptual transmission configurations identified by the Technical Analysis Committee; and a range of natural gas prices and possible capital costs and performance for new electric generation facilities.

FEAST stands for Frontier Economic Analysis Screening tool. FEAST was developed for the Western Regional Transmission Expansion Partnership who was interested in determining the feasibility of constructing the Frontier Line. The analytical underpinning of this tool and its structure are briefly described in this report. FEAST is a simple tool for sophisticated users. It focuses on incremental resources, not a complete supply stack, and facilitates quantification of regional cost differences. FEAST is a screening tool, and is not intended as a substitute for

³ WECC is responsible for coordinating and promoting electric system reliability throughout the West including the provinces of Alberta and British Columbia, the northern portion of Baja California, Mexico, and all or portions of 14 western states. Any transmission planning alternative that emerges from the WECC process would undergo all applicable governmental permit and environmental review processes, including public participation, before construction could commence.

⁴ The three committees are the Loads and Resources Working Group, Technical Analysis Committee and the Economic Analysis Committee.

necessary, in-depth analysis using production costing and/or market simulation tools. The FEAST tool also met the EAC's desire that the tool promotes transparency and facilitates leveraging pre-existing work, both in the public domain and proprietary.

The EAC identified, collected, assessed, and synthesized data inputs to FEAST. Key drivers were identified, and attention devoted to identifying the range of uncertainties associated with the key drivers. A reference set and a range of FEAST inputs were determined on costs and performance data for renewable resources, gas-fired resources, and greenhouse gas adders.

The EAC performed a variety of analyses. Not all the analysis performed by the EAC is described in this report. This report presents analysis of four cases, which highlight the key findings of the EAC.

The EAC performed its work using a participatory stakeholder process. The stakeholder process is described in this report. A list of the EAC members is included in Appendix A.

2. *Process*

The EAC was established in December 2006. The initial members of the Economic Analysis Committee were representatives from the Steering Team member companies. Todd Strauss and Manho Yeung of PG&E are the co-chairs of the Economic Analysis Committee.

At the first Stakeholder Meeting, in San Francisco on December 12, 2006, Manho Yeung presented an initial framework for the economic screening analysis. Stakeholders were invited to join the Economic Analysis Committee. There are currently 14 individuals in EAC representing ten organizations.

Weekly EAC conference calls were instituted between April and July 2007. The EAC reviewed the scenarios evaluated by the Loads and Resources Working Group, and the conceptual transmission links and associated costs provided by the Technical Analysis Committee. Discussion quickly focused on three areas: inputs, outputs, and analytical tool.

In weekly conference calls and via e-mail, the EAC identified the outputs required for effective analysis, and the plan for the analysis. The EAC reviewed the FEAST tool developed for the Frontier Line and agreed to employ it for the screening analysis. The EAC reviewed economic and resource assumptions and agreed to a set of reference inputs and a range of inputs for the screening analysis.

At the second Stakeholder Meeting in Portland on August 2, 2007, EAC members presented the work accomplished by the EAC along with updates from the other two committees. The reference set of data inputs was described. Numerical results for sample cases were presented, along with sensitivities. A variety of stakeholder comments were provided and questions were addressed.

Since the August Stakeholder Meeting, the work of the Economic Analysis Committee has been winding down. The last conference call was held on August 9, 2007. The drafting of this

committee report was accomplished via e-mail. The report of the Economic Analysis Committee was posted on the C/PNW-NC Line Project Regional Planning Review web site on October 10, 2007. In response to stakeholder feedback, further edits were made. This version of the report is dated October 23, 2007.

3. Methodology

This section discusses benefit-cost analysis in the context of the C/PNW-NC Line feasibility study. This section describes the tool, FEAST, used by the Economic Analysis Committee to perform its benefit-cost analysis.

Benefit-Cost Analysis

Economic analysis of the C/PNW-NC Line has been grounded in benefit-cost analysis. Benefit-cost analysis is a widely recognized technique of economic analysis. Performing benefit-cost analysis includes tasks of estimating dollar-denominated streams of benefits and costs, discounting future benefits and costs to account for the time value of money, and comparing the present value of benefits to the present value of costs.

To assess electric transmission possibilities and compare electric transmission alternatives, the Economic Analysis Committee estimated the ratio of benefits to costs (benefit-to-cost ratio). A benefit-to-cost ratio greater than 1.0 indicates the value of benefits are greater than the costs, while a benefit-to-cost ratio less than 1.0 indicates the value of benefits are less than the costs.

The Economic Analysis Committee tried to measure all benefits and costs in 2006 constant US dollars. Costs associated with transmission lines and power plants that may be built years from now are nonetheless expressed in 2006 US dollars. The Economic Analysis Committee assumed an in-service year of 2015 for the C/PNW-NC Line and the generating resources.

The potential benefits of the C/PNW-NC Line are multifaceted. The purpose of the C/PNW-NC Line is to enable new renewable resources to be developed and delivered to distant locations, providing a variety of benefits to customers in WECC. Benefits quantified by the Economic Analysis Committee include energy, capacity, transmission losses (a “negative” benefit), and avoided greenhouse gas emissions. The EAC also identified two other potential benefits: improvements to grid efficiencies and opportunities for seasonal power exchange, and modified the FEAST tools to account for them.

To account for the difference in timing between the transmission investment and the realization of benefits, both costs and benefits are represented as levelized amounts. Levelization transforms a stream of payments (costs or benefits) that varies over time into a stream that is constant over time. Levelization results in the present value of the constant stream equal to the present value of the original time-varying stream, thus preserving a critical economic feature of the original time-varying stream. Levelization is a commonly-used technique in the energy industry to measure costs and benefits.

For benefit-cost analysis of the C/PNW-NC Line, costs are largely associated with the transmission investment. Costs associated with generation are included in the analysis, of course, but expressed as avoided cost, hence a benefit. As discussed later in this report, the essential nature of the analysis performed by the Economic Analysis Committee is to compare generation costs for different regions, and estimate the opportunity cost savings enabled by the C/PNW-NC Line.

Screening Tool

FEAST is not a substitute for production costing and/or market simulation tools. Analysis using FEAST may be a first step, to quickly sort through a multitude of possibilities. It must be followed by necessary, in-depth production costing and/or market simulation analysis of a few possibilities. In submitting this report, the Economic Analysis Committee envisions that any further economic analysis associated with the C/PNW-NC Line is more in-depth and uses production costing and/or market simulation tools.

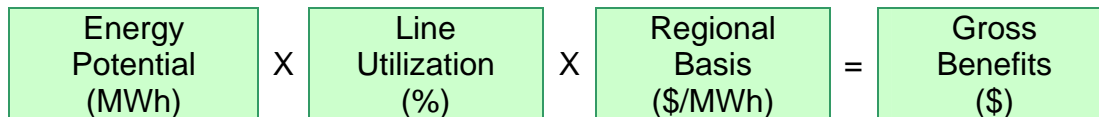
FEAST is structured so that stakeholders can input their assumptions in a “what-if” manner and see the impacts to the transmission line’s benefits and costs. Because FEAST is a simple interactive tool intended for sophisticated users, there are few built-in checks to validate data inputs. The user is responsible for ensuring valid and appropriate resource costs, operating characteristics; fuel costs, price adders, and so forth are input. The user must take special care to ensure the validity of the input data set as a whole, since a number of inputs interact to produce results. The user must check that FEAST output makes sense.

Analytical Underpinnings of FEAST

Applying benefit-cost analysis to the C/PNW-NC Line is a matter of calculating gross benefits, gross costs, and comparing the two. As illustrated in Figure 1, gross benefits are represented as the product of energy potential, line utilization, and regional basis.

Figure 1

Accumulating Gross Benefits



- **Energy Potential** is the amount of energy that would flow over a transmission line if power flowed all the time at the full rating of the over the transmission line. For example, a transmission line rated at 2,000 megawatts (MW) would have an energy potential of 2,000 MW x 8,760 hours/year, equal to 17,520 gigawatt-hours (GWh) or 17.52 million megawatt-hours (MWh) per year. Note that the Energy Potential of a given transmission line represents its full rating and is not determined based on the import capability of the line that could be calculated using the technical power flow studies.

- **Line Utilization** is a fraction between zero and one representing the level of use of the transmission line: the greater the number, the greater the use. Line utilization is the ratio of the actual or forecast energy flowing over the transmission line in a period divided by the energy potential of the transmission line for that period. Line utilization is a function of the quantity and characteristics of the resources available for generation at the transmission line's endpoints.
- **Regional Basis** describes the difference in energy production cost between the generation or source region and the load or sink region. It is measured in dollars per MWh. Regional basis is influenced by many factors including resource construction costs, amount of energy production, fuel prices, environmental mitigation costs, renewable energy price premiums, just to name a few. Regional basis is essentially the opportunity cost savings associated with power flowing over the C/PNW-NC Line rather than being produced locally at the sink (Northern California in this case).

FEAST simplifies the regional basis calculation by assuming that energy is produced by or displaced at a new generation plant. An alternate means to evaluate the regional basis is assuming a marketing entity contracting with generators, aggregating and firming the energy for delivery to the sink region. This would result in more consistent line utilization (i.e., a higher line utilization factor), but at an "aggregation adder" cost. Since it is unclear about the costs and characteristics of such an aggregation arrangement, the Economic Analysis Committee uses the more simple incremental energy production and displacement approach for this analysis.

Gross costs are largely associated with development and construction of transmission lines. The Technical Analysis Committee estimated total cost, on a scale of billions of dollars, for each complete transmission configuration. FEAST enables quick conversion of this total cost for transmission to a unit cost, in dollars per MWh. This conversion depends on a number of assumptions,⁵ and the assumptions are intended to be transparent in FEAST.

FEAST is intended to focus on incremental resources, not a complete supply curve or supply stack. FEAST focuses on the energy benefits associated with the C/PNW-NC Line. To properly do so, inputs should specify that source and sink regions are in energy balance.

Output of FEAST

The output of FEAST includes a summary table and a benefit-to-cost ratio break-even curve. An example of the output table is displayed in Figure 2. An example of the benefit-to-cost ratio break-even curve is displayed in Figure 3.

The output table (Figure 2) documents the transmission alternative selected. It also lists the energy potential (or line capacity), utilization factor, and regional price difference. The product of these three terms is the gross benefit. The benefit-to-cost ratio is gross benefit divided by gross cost.

⁵ For example, a 2% inflation rate, an after tax discount rate of 7.5% for utility financing and an after tax discount rate of 8.5% for merchant financing were used in this screening analysis.

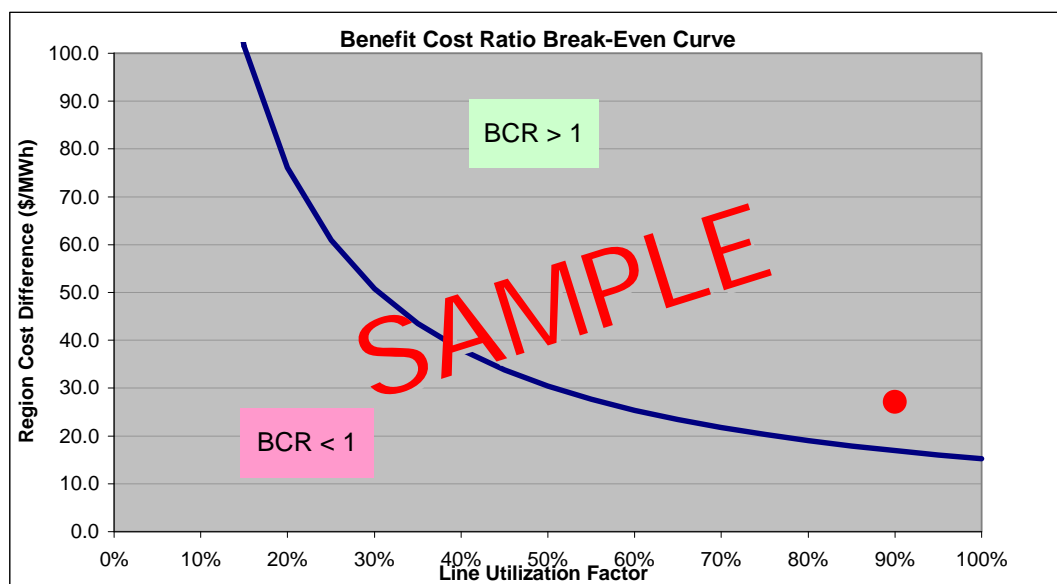
The benefit-to-cost break-even curve (Figure 3) displays FEAST output results graphically. The horizontal axis indicates line utilization (a percentage) while the vertical axis indicates regional price difference (in dollars per MWh). The blue curve shows the intersection of utilization factor and regional price difference where the transmission line's benefits equal its costs (break-even). The area under the blue curve represents conditions under which the transmission line has benefit-to-cost ratio less than 1.0 while the area above the blue curve represents conditions under which the line has benefit-to-cost ratio greater than 1.0. The red dot denotes the result of the FEAST model run. Since FEAST is only a screening tool, benefit-to-cost ratios produced by FEAST are intended to be indicative, not definitive.

Figure 2
Sample FEAST Output Table

TOTAL SYSTEM					
Trans Option No.	1	Installed Cost (\$Million)			4,050
		Capacity (MW)			3,000
Description	Canada 500 kV AC Double Circuit Tower Line				
Line Utilization	90%				

	(\$/MWh)	Regional Difference			Annual Benefits (\$Million)	Annual Cost (\$Million)
		Source (\$/MWh)	Sink (\$/MWh)	Diff (\$/MWh)		
Line Cost	16.9				400	
Power Cost		75.6	109.6	34.0	803	
GHG Adder		0.0	0.0	0.0	0	
CO2 for EOR		0.0	0.0	0.0	0	
Renewable Credit		0.0	0.0	0.0	0	
System Integration		0.0	1.0	1.0	25	
Prod Tax Credit		0.0	0.0	0.0	0	
Losses		6.2		-6.2	-147	
Grid Eff		0.0		0.0	0	
Dependable Cap Value			-1.7	-1.7	-40	
Winter Cap Return Value		0.0		0.0	0	
TOTAL		81.9	109.0	27.1	642	
Benefit to Cost Ratio	1.60				400	

Figure 3
Sample FEAST Benefit-to-Cost Ratio Break-Even Curve



4. Work Plan

The EAC simplified the screening analysis by focusing the evaluation on the economic attractiveness of displacing resources at the sink location (Northern California) by resources at the source location (British Columbia) assuming a particular transmission line alternative. The following table shows the scenarios the EAC evaluated:

Table 1
Screening Analysis Work Plan

<i>New Resources in BC</i>				<i>N. CA Resources to be Displaced</i>
<i>No.</i>	<i>Wind</i>	<i>Small Hydro</i>	<i>Biomass</i>	
A	3000 MW			1. Combined Cycle (CC) 2. Wind 3. Solar 4. Renewable Mix
B		3000 MW		1. Combined Cycle (CC) 2. Wind 3. Solar 4. Renewable Mix
C			3000 MW	1. Combined Cycle (CC) 2. Wind 3. Solar 4. Renewable Mix
D	1000 MW	1000 MW	1000 MW	1. Combined Cycle (CC) 2. Wind 3. Solar 4. Renewable Mix

Cases A, B and D were examined in two modes: first, as shown, with an assumption limiting the installed capacity of resources to the transmission line limit; and second, with an additional amount of installed hydro and/or wind capacity above the transmission line limit under the assumption that the amount of excess energy is expected to be small and most can be absorbed locally. We selected a 20% as the amount of “overbuild” based on analyses performed for other markets.⁶ The increased capital cost of the added wind generation capacity is included in the analysis here, and so is the resulting higher utilization of the transmission line. Summary results are provided for with and without this 20% overbuild assumption.

The intent of this 20% “overbuild” case is not to represent an energy aggregation, shaping and firming evaluation. For such a scenario, the line utilization factor is expected to be higher in the

⁶ Additional analyses are needed to determine if the British Columbia and Pacific Northwest can accommodate this additional 20% overbuilt as well as additional costs needed for such “accommodation.”

60-70% range and accompanied by a corresponding increase in service cost. Summary results are provided for both sets of assumptions.

The EAC conducted a number of sensitivity runs to identify variables that really matters and identify the variables' interactions that drive results. The following are some of the variables for the sensitivity analysis:

- (1) Natural Gas Price;
- (2) CO2 Greenhouse Gas Adder;
- (3) Resource Installation Cost;
- (4) Resource Capacity Factor; and
- (5) Grid Improvement and Seasonal Power Exchange Benefits.

The BC renewable Mix (Case D) is based on a mix of resources which on an installed capacity basis is split roughly equally between Biomass, Small Hydro and Wind (1000/1000/1000 MW). On an energy basis this translates to a mix consisting of 52% Biomass, 25% Small Hydro and 23% Wind.⁷

The EAC examined several different combinations of resources for use as the California renewable mix. The EAC settled on a mix consisting of 15% geothermal, 50% solar (CSP) and 35% wind on an energy basis. Other combinations⁸ were evaluated as part of the sensitivity analysis with results bounded by the 100% wind and 100% solar cases.

5. Input Data and Assumptions

Input assumptions for this analysis were selected to test what-if situations and they do not necessary represent the view of the Economic Analysis Committee.

British Columbia Resources

The EAC used data from BC Hydro's 2006 Integrated Electricity Report, Appendix F as the basis for its reference set starting point for renewable resources in British Columbia. Table 2 shows the range of renewable resource installed capital cost and performance data.

⁷ For the 20% overbuilt scenario with 1000 MW biomass, 1200 MW small hydro and 1200 MW wind, the energy mix would be 48% Biomass, 27% Small Hydro and 15% Wind

⁸ Such as 15% geothermal, 35% solar and 50% wind.

Table 2
British Columbia Renewable Resource Data

Resource	Name	Installed Capacity (MW)	Annual Energy (GWh)	Capacity Factor (%)	Installed Cost* (\$Million)	Installed Cost* (\$/kW)
Wind	Vancouver Island 1	450	1,375	34.9	780	1,734
Wind	Vancouver Island 2	300	800	30.4	520	1,734
Wind	Vancouver Island 3	300	700	26.6	520	1,734
Wind	North Coast Onshore 1	400	950	27.1	874	2,185
Wind	North Coast Onshore 2	500	1,080	24.7	1092	2,185
Wind	North Coast Onshore 3	350	700	22.8	765	2,185
Wind	North Coast Offshore 1	600	2,400	45.7	1734	2,891
Wind	North Coast Offshore 2	600	2,220	42.4	1734	2,891
Wind	North Coast Offshore 3	300	1,020	38.8	867	2,891
Wind	Peace River 1	400	1,510	43.1	628	1,571
Wind	Peace River 2	400	1,430	40.8	628	1,571
Wind	Peace River 3	600	1,935	36.8	943	1,571
Biomass	Biomass - Wood Waste	157	1,256	91.3	323	2,054
Small Hydro	Small Hydro 1	260	1,000	43.9	628	2,417
Small Hydro	Small Hydro 2	400	1,430	40.8	628	1,571
Small Hydro	Small Hydro 3	600	1,935	36.8	943	1,571

* converted to 2006 US dollars

Based on BC Hydro's data and input from stakeholders, the EAC selected the following as the reference set starting point for the analysis:

Table 3
British Columbia Renewable Resource Reference Points and Ranges

	Reference Point	Range
Wind Installed Cost:	\$2,000/kW	\$1,500 to \$2,500/kW
Wind Capacity Factor:	40%	32% to 48%
Biomass Installed Cost:	\$2,200/kW	\$1,800 to \$2,600/kW
Biomass Capacity Factor:	90%	
Small Hydro Installed Cost:	\$2,000/kW	\$1,800 to \$2,800/kW
Small Hydro Capacity Factor:	44%	36% to 48%

Since the EAC has difficulties in locating information on O&M costs for the BC resources, it relied on assumptions used in the Frontier Line analysis work for generation resources in California. This screening analysis uses the same fixed O&M cost of \$11.5/kW-year, a variable O&M cost of \$5.5/MWh, a 21% dependable capacity factor,⁹ and an integrated cost of \$3/MWh

⁹ The **Capacity Factor** of a power plant is the ratio of its actual output over a period of time and its output if it had operated a full capacity of that time period. This is calculated by totaling the energy the plant produced and dividing it by the energy it would have produced at full capacity. On the other hand, **Dependable Capacity** is the amount of megawatts a plant can reliably produce when required, typically measured during periods when electric demand is at its highest. **Dependable Capacity Factor** is the ratio of a power plant's dependable capacity and its installed full capacity.

for both BC¹⁰ and California wind. Please note that the capacity factor for BC wind resources, similar to California wind resources, assumes wind turbines at a 70 meter hub height and using an assumed GE 1.5 MW turbine.

For biomass, the screening analysis uses a variable O&M of \$95.7/kW-year and a variable O&M cost of \$5.2/MWh. For small hydro, the screening analysis uses a variable O&M of \$50/kW-year and a variable O&M cost of \$2/MWh. During the drafting of this report, we received additional comments that there are additional charges in terms of a water rental energy fee and a capacity fee for small hydro facilities in BC. These water rental fees should be included in the analysis and will correspondingly reduce the benefit-to-cost ratio.

California Resources

The EAC, with certain adjustments, relied on data and assumptions used in the Frontier Line analysis work for generation resources in California.

Wind

In the Frontier Line Analysis, the capacity factor of a 500 MW wind project in the Tehachapi Wind Resource Area was used as a proxy for all California wind generation. TrueWind calculated the average annual capacity factor at this site for the three years 2002-2004 to be 37.0%, at a 70 meter hub height and using an assumed GE 1.5 MW turbine. For comparison, typical capacity factors from existing wind resources in California is in the 20-30% range, although more modern wind installations comparable to the ones modeled for BC are expected to average about 36%. For the C/PNW-NC Line analysis, a 30% capacity factor is selected as the reference case with a range of 22% to 37%.

Wind dependable capacity for this analysis is based on its capacity factor during the hours, noon to 6:00 pm for the peak period May through September. A dependable capacity of 21% for California wind generation was selected so that dependable capacity is calculated using the same techniques and same data source for all regions, and is appropriately comparable across regions.

Wind power capital and operating costs were taken from the on-going national 20% wind penetration scenario study being developed by the US Department of Energy, NREL, American Wind Energy Association (AWEA) and Black & Veatch. These capital costs shown below also correspond closely to those used in recent WECC studies¹¹—when increased roughly to 35% to account for commodity price increases (steel, copper, cement), and for the effect of the worldwide shortage of wind turbine supply. California installed wind project cost was increased a further \$200/kW to account for transmission necessary to connect wind resource areas to the state high-voltage grid. Wind power capital costs are expected to decline from \$1,680/kW in

¹⁰ The application of a \$3/MWh integration cost appears to be reasonable for a system like California. However, the same number may not be applicable to British Columbia since it has a much higher proportion of hydroelectric generation and significant hydro storage. Further analysis is needed to better quantify integration costs in British Columbia.

¹¹ CDEAC/SSG-WI 2005 Transmission Planning Program, 2015 Reference Case Key Assumptions Matrix; NTAC 2005-2006 Canada-California Assumptions.

2007 to \$1,300/kW in 2015 due to efficiency improvements, manufacturing economies, easing of the turbine supply shortage and stabilization of commodity prices. Based on stakeholder input from the August 2, 2007 meeting, we selected \$2,000/kW as the reference case starting point. A range of \$1,500 to \$2,500/kW is used for the installed cost. This same cost assumption is being used for wind resources located in British Columbia.

Table 4
Wind Capital and Operating Costs

Installed Cost, 2015, California	\$2,000/kW
Fixed O&M	\$11.50/kW-year
Variable O&M	\$5.50/MWh

Fixed O&M costs include land lease/royalty payments; taxes, insurance, on-site electricity, and administrative/management fees associated with operating the wind projects.

Wind integration costs are those of any incremental generation committed and/or dispatched to balance the system with variable-output wind added. Many integration studies of different regions of the US and Europe for wind penetrations up to 20% indicate that such costs typically range from \$1.50/MWh to \$5.00/MWh. The reference data set uses a value of \$3.00/MWh, roughly at the midpoint of this cost range.

Concentrating Solar Power (CSP)

Various CSP technologies provide large-scale peaking power. Capital and operating cost data were taken from an April 2006 study of CSP technology and projects performed by NREL and Black & Veatch for the California Energy Commission.¹² Consultation with developers of CSP projects proposed for California and the desert Southwest indicated the cost and performance information in this report to be in the expected range for construction in 2015.

Costs are shown for parabolic trough technologies, with six hours of storage. Size is assumed to be 200 MW. Storage raises the effective capacity factor from 28% to 40%, and accounts for roughly 18% of total direct project cost. Fixed operations and maintenance (O&M) costs include costs of labor, administration, water treatment, spares and equipment; other fixed costs include land payments, taxes and insurance.

Table 5
California Concentrating Solar Power Costs and Capacity Factor

Installed Cost, 2015	\$3,150/kW
Fixed O&M	\$38.00/kW-year
Other Fixed Costs	\$75.20/kW-year
Variable O&M	\$1.50/MWh
Capacity Factor	40.4%

¹² L. Stoddard, J. Abiecunas, and R. O'Connell, "Economic, Energy and Environmental Benefits of Concentrating Solar Power in California," NREL Subcontract Report SR-550-39291, April 2006.

A range of \$2,750/kW to \$3,300/kW is used for the installed cost. A range of 30% to 45% is used for the capacity factor.

As with wind power, CSP dependable capacity is its capacity factor during the hours, noon to 6:00 pm for the peak period May through September. Using solar output load shapes supplied by NREL for various locations, the reference set values for CSP Dependable Capacity are displayed in Table 6.

As CSP technology continues to advance, additional analyses and evaluations are needed to determine its cost-effectiveness.

Table 6
California Concentrating Solar Power Dependable Capacity

	CSP, no storage	CSP, with storage
California (Barstow)	87%	100%
Non-California (Las Vegas)	80%	100%

Geothermal

Geothermal project capital and operating costs vary widely with the very different physical characteristics of Known Geothermal Resource Areas (KGRAs). For the Frontier Line feasibility study, data for geothermal resources at the Salton Sea, in California’s Imperial Valley, was used. The Salton Sea KGRA has the largest amount of development potential—approximately 2,000 MW of proven reserves—of any region in the US. Because of very high concentrations of dissolved solids in highly corrosive brine, along with very high temperatures and pressures, capital and operating costs in the Imperial Valley are much higher than at other KGRAs. Costs were provided by MidAmerican Energy, which operates 540 MW of geothermal plants at the Salton Sea and owns development rights to an additional 2,000 MW of resource capacity there. Other Fixed Costs are negative, after incorporating the Geothermal Depletion Allowance afforded to such plants.

Table 7 displays the costs associated with a generic geothermal project in California’s Imperial Valley, and are not intended to apply to costs for a geothermal project elsewhere.

Table 7
California Geothermal Costs and Capacity Factor

Installed Cost, 2015	\$3,600/kW
Fixed O&M	\$64.00/kW-year
Other Fixed Costs	(\$6.20)/kW-year
Variable O&M	\$23.60/MWh
Capacity Factor	95%

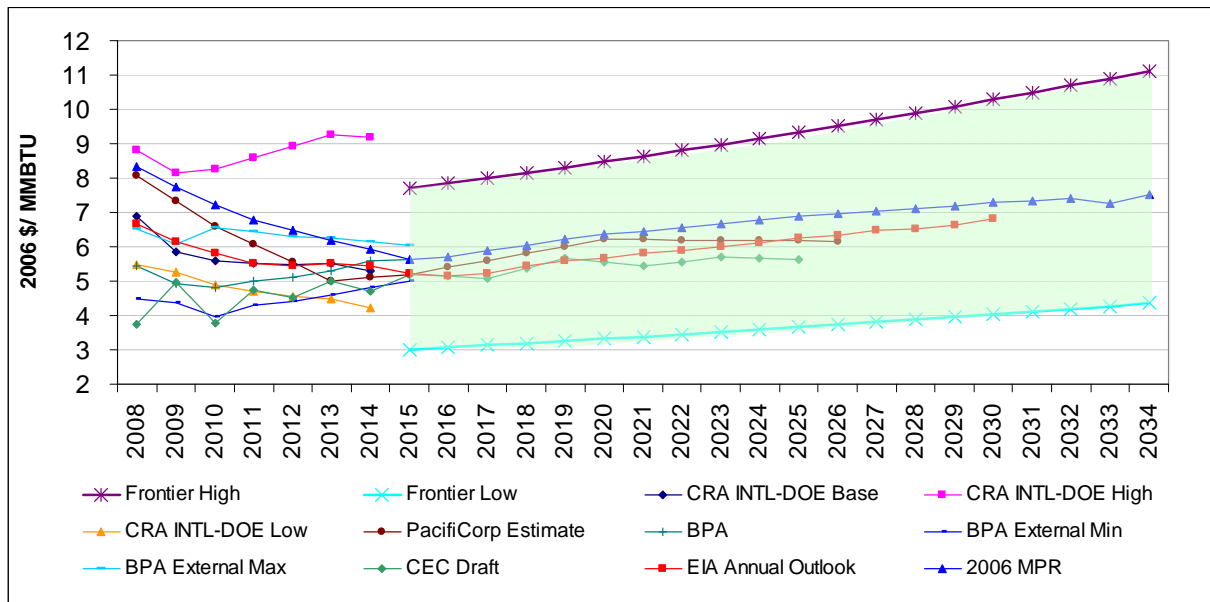
Natural Gas

This section describes natural gas prices and cost and performance data for gas-fired resources. Data sources are identified. Considerations affecting choice of particular input assumptions are discussed.

Natural gas price inputs to the screening analysis have two components: commodity and transportation. In the reference data set, commodity cost is based on a projection of the Henry Hub natural gas forecast. The transportation component is used to represent the basis difference in the cost of gas between the actual pricing point of the gas-fired generating resource and the Henry Hub price.

The commodity component is based on a projection of the Henry Hub natural gas price for a twenty-year period, 2015 to 2034. In developing the inputs for the commodity component of natural gas price, a wide range of available long-term Henry Hub gas forecasts was examined. Figure 4 below displays a few long-term forecasts of Henry Hub gas prices. Real, not nominal, prices are displayed, that is, prices in 2006 constant dollars per MMBtu.

Figure 4
Long-term Natural Gas Price Forecasts



The two forecasts labeled Frontier High and Frontier Low indicate the upper and lower levels, respectively, of natural gas prices used in the Frontier Line feasibility study. The Economic Analysis Committee based on this study and expectations of future gas prices elected to use a set of gas prices shifted a \$1.00/MMBtu higher. For use in the C/PNW-NC Line study, on a levelized 2006 dollars per MMBtu basis, this resulted in a range of \$4.50 to \$10.00/MMBtu, and a reference starting point of \$7.00/MMBtu. .

The transportation component reflects the difference in price from Henry Hub to the actual pricing point. The reference set has the California transportation component equal to zero dollars per MMBtu. This is based on a combination of market quotes for near term basis swaps of approximately negative \$0.50 per MMBtu for PG&E Citygate and SoCal pricing points—that is, fifty cents less than Henry Hub—and a local distribution charge forecast at 0.40 dollars per MMBtu. The reference set has no specific transportation component for locations outside California because the transportation component is very dependent on the particular location of a gas-fired power plant. In specifying an appropriate transportation component, one should include any applicable basis differential, local distribution charges and fuel taxes.

Costs and operating characteristics for gas-fired combined-cycle (CC) and combustion turbine (CT) technologies are also part of the reference data set.

CC plant costs and operating assumptions are based primarily on information associated with setting California’s 2006 Market Price Referent (MPR).

The Economic Analysis Committee recognized that uncertainty exists in both the cost and operating profile of future CCs. A range of plausible capacity factors was identified. A lower level of 50% corresponds to the operation of some of today’s CCs, while an upper level of 90% corresponds to baseload operation. For the reference data set input to FEAST, a capacity factor of 78% was identified.

**Table 8
Combined Cycle (CC) Costs and Performance**

	Heat-Rate BTU/kWh	Capacity Factor	Depend. Capacity Factor	Installed Cost 2006\$/kW	Fixed O&M* \$/kW-Yr	Other Fixed* \$/kW-Yr	Variable O&M* \$/MWh
Combined Cycle - CA	6920	78%	100%	1000	13.7	37.7	2.4
Combined Cycle - Non CA	6920	78%	100%	1000	13.7	37.7	2.4

Combustion turbine plant costs are also based primarily on information from California’s Market Price Referent (MPR) Process. The 2006 MPR process, however, did not address the cost structure of a new combustion turbine. The \$750 per kW installed cost was developed by maintaining the relative percentage cost differential found in the 2004 MPR process and applying it to the combined cycle cost of the 2006 MPR process. The 9,300 Btu per kWh heat rate is representative of today’s combustion turbine technology. Uncertainty exists in both the cost and operating profile of future combustion turbines. The technology of new combustion turbines will impact the heat rate, cost and operating profile. For example, newer technology may provide a better heat rate, but with a higher installed cost. As a package, the Committee thought that the assumptions below were appropriate for use as reference inputs for the C/PNW-NC Line study.

Table 9
Combustion Turbine (CT) Costs and Performance

	Heat-Rate BTU/kWh	Capacity Factor	Depend. Capacity Factor	Installed Cost 2006\$/kW	Fixed O&M* \$/kW-Yr	Other Fixed* \$/kW-Yr	Variable O&M* \$/MWh
Combustion Turbine - CA	9300	10%	100%	750	12.3	25.3	9.9
Combustion Turbine - Non CA	9300	10%	100%	750	12.3	25.3	9.9

*2006 dollar denominated levelized costs

Greenhouse Gas (GHG) Adders

Substantial attention is now being paid to the prospects for global warming. In 2006, California enacted two laws to address Global Warming. California Senate Bill 1368 (restriction on CO₂ levels associated with long-term contracts for base load generation) is intended as an interim measure that essentially prohibits California utilities from contracting for new construction of conventional pulverized coal plants. California Assembly Bill 32 (Global Warming Solutions Act of 2006) is the more definitive legislation. This Act caps California's greenhouse gas emissions at 1990 levels by 2020. This legislation requires the California Air Resources Board (CARB) to adopt a GHG emissions cap on all major sources, including the electricity and natural gas sectors, to reduce statewide emissions of GHG to 1990 levels. In Rulemaking 06-04-009, the California Public Utilities Commission (CPUC) proposes to develop and bring a joint recommendation of both the CPUC and the CEC to CARB for its consideration when adopting the overall "scoping plan" as called for in AB 32 to govern the GHG emissions limits in California overall. The schedule for the CARB activity is that in October 2008 the CARB staff will finalize its "scoping plan" for Board adoption in November 2008. Other western states are also formulating strategies to address GHG issues.

Based upon work completed for the Frontier Line Analysis, a GHG adder range of \$9 to \$70 per ton of CO₂ was used for the C/PNW-NC Line economic screening analysis. A point estimate of \$20 per ton of CO₂ is used for the reference starting case.

Table 10 summarizes the starting point data set assumptions for the different resources and their calculated levelized power cost in \$/MWh assuming a 2015 in service date and in 2006 US \$.

Table 10
Calculated Levelized Power Costs

		Reference Set Starting Point Data			Calculated Power Cost (\$/MWh)
		Installed Cost (\$/kW)	Capacity Factor (%)	Local Transmission (\$/kW)	
BC	Biomass	2200	90	200	73
BC	Small Hydro	2000	44	200	69
BC	Wind	2000	40	200	77
CA	Combined Cycle	1000	78	0	73
CA	Geothermal	3600	95	0	76
CA	Solar (CSP)	3150	40	0	126
CA	Wind	2000	30	200	101

6. Analysis

Using FEAST version 3.0 modified for the C/PNW-NC Line and the reference set of input values as a starting point, the Economic Analysis Committee evaluated four study cases (see Table 1 - Work Plan) on a “backbone” transmission configuration. Transmission alternative 1 was identified as the “backbone” configuration. This is a \$4.05 billion, 3,000 MW alternating current (AC) line from British Columbia to northern California with intermediate connection points in Washington and Oregon. The annualized cost for this line is \$400 million (in 2006 US dollars). This cost is the same for all four cases. The cost per (flowing) MWh does vary across cases, as only the line utilization varies across cases. Additional analysis on transmission line cost and other assumptions uncertainties are presented in the Sensitivity subsection starting on page 39.

Tables 11 to 13 summarize the multiple sub-cases under four sets of cases and the corresponding benefit-cost ratio results. Figures 5 to 20 display elements of the output worksheets for the four set of cases. As stated earlier in this report and we believe worth repeating here again, this is a screening analysis using the FEAST tool, benefit-to-cost ratios produced by FEAST are intended to be indicative, not definitive. More complete studies are needed to determine the project viability.

Case A – British Columbia Wind vs. California Resources

Case A results are displayed in Figure 5 to 8. Case A1 compares wind resources in British Columbia to Combined Cycles in California. Case A2 compares BC wind with California wind. Case A3 compares BC wind with California CSP. Case A4 compares BC wind with California geothermal, CSP, and wind mix on a 15/50/35 energy basis. While the transmission line capacity is 3,000 MW, the Economic Analysis Committee evaluated the analysis in two modes: first, with an assumption limiting the installed capacity of resources to the transmission line limit; and second, with an additional amount of installed hydro and/or wind capacity above the transmission line limit under the assumption that excess can be absorbed locally. The EAC judged some amount of additional wind capacity could be assigned to British Columbia, with the

understanding that, for an example, when more than 3000 MW of wind resources are generating, the energy is absorbed locally rather than flowed over the long-haul transmission line, or some of the excess capacity is curtailed. Relying on analyses performed for other markets, the Economic Analysis Committee assumed the maximum amount of additional wind capacity to be absorbed locally as 20%. The increased capital cost of the added wind generation capacity is included in the analysis here, and so is the resulting higher utilization of the transmission line. In summary, the analysis was conducted with and without this additional 20% wind capacity.

Table 11
Summary of Benefits-to-Cost Ratios without Overbuild

	(1) CA CC	(2) CA Wind	(3) CA CSP	(4) CA RPS Mix
(A) 3000 MW BC Wind	0.0	0.4	0.8	0.5
(B) 3000 MW BC Hydro	0.1	0.8	1.3	0.9
(C) 3000 MW BC Biomass	0.0	1.4	2.3	1.6
(D) 3000 MW BC Mix	0.0	0.9	1.5	1.0

As described earlier, the Economic Analysis Committee also evaluated scenarios with overbuilding resources in British Columbia. Table 13 below shows the resulting benefit-to-cost ratio results which are slightly higher in some cases. Output graphs for cases with the 20% are listed as Figures 5-20. Output graphs for cases without the 20% additional capacity are available upon request.

Table 12
Summary of Benefits-to-Cost Ratios with Overbuild

	(1) CA CC	(2) CA Wind	(3) CA CSP	(4) CA RPS Mix
(A) 3600 MW BC Wind	0.0	0.5	1.0	0.6
(B) 3600 MW BC Hydro	0.1	1.0	1.5	1.1
(C) 3000 MW BC Biomass	0.0	1.4	2.3	1.6
(D) 3400 MW BC Mix	0.0	1.0	1.6	1.1

Table 13 below is yet another format to show the same benefit-to-cost results for the cases but with more details:

Table 13
Results of Cases with 20% Overbuild

Case	Source: British Columbia	Sink: California	Line Utilization	Regional Basis (\$/MWh)	Line Cost (\$/MWh)	Benefit-to- Cost Ratio
A1	3600 MW Wind	1846 MW CC ¹³	48%	6.7	31.7	<0
A2	3600 MW Wind	4800 MW Wind	48%	16.7	31.7	0.5
A3	3600 MW Wind	3565 MW CSP	48%	32.1	31.7	1.0
A4	3600 MW Wind	1680 MW Wind 1785 MW CSP 226 MW Geothermal	48%	20.1	31.7	0.6
B1	3600 MW Small Hydro	2031 MW CC	53%	18.4	28.8	0.1
B2	3600 MW Small Hydro	5280 MW Wind	53%	28.4	28.8	1.0
B3	3600 MW Small Hydro	3921 MW CSP	53%	43.8	28.8	1.5
B4	3600 MW Small Hydro	1845 MW Wind 1965 MW CSP 250 MW Geothermal	53%	31.8	28.8	1.1
C1	3000 MW Biomass	3462 MW CC	90%	13.7	16.9	<0
C2	3000 MW Biomass	9000 MW Wind	90%	23.8	16.9	1.4
C3	3000 MW Biomass	6683 MW C	90%	2.1	16.9	2.3
C4	3000 MW Biomass	3150 MW Wind 3345 MW CSP 425 MW Geothermal	90%	27.1	16.9	1.6
D1	1200 MW Wind 1200 MW Small Hydro 1000 MW Biomass	2446 MW CC	64%	13.2	23.9	<0
D2	1200 MW Wind 1200 MW Small Hydro 1000 MW Biomass	6360 MW Wind	64%	23.3	23.9	1.0
D3	1200 MW Wind 1200 MW Small Hydro 1000 MW Biomass	4723 MW CSP	64%	38.6	23.9	1.6
D4	1200 MW Wind 1200 MW Small Hydro 1000 MW Biomass	2225 MW Wind 2355 MW CSP 304 MW Geothermal	64%	26.5	23.9	1.1

Proper use of FEAST results in energy balance. For Case A1, 12,614 GWh is indicated in Figure 5 and corresponds to a line utilization factor of 48 percent with the 20% additional capacity.¹⁴ Because combined cycles have higher capacity factor, a smaller amount of combined cycle capacity is needed to balance the energy from 3,600 MW of wind. Thus, this case compares 3,600 MW of wind with just 1,846 MW of combined cycle. The analysis can be interpreted as investigating which is a more economically efficient incremental resource for the California market: 3,600 MW of British Columbia wind (including transmission costs) or 1,846 MW of California combined cycle.

¹³ Displacing California combined cycle with renewable energy imported over the C/PNW-NC Line is economically feasibility if natural gas price and greenhouse gas adder are high.

¹⁴ Output graphs for cases without the 20% additional capacity are available upon request.

In addition, the dependable capacity of a combined cycle is substantially greater than the dependable capacity of an intermittent wind resource. The results reflect this. An annual dependable capacity value “benefit” in the amount of negative 44 million dollars is associated with the British Columbia wind resource.

Energy benefits are negative \$8.2/MWh, levelized. This corresponds to negative 104 million dollars annually, in 2006 dollars. The energy benefits result from opportunity cost savings from having the wind resource and the C/PNW-NC Line rather than a gas-fired combined cycle in California which is negative in the case of Case A1. While the capital cost of the wind resource is greater, the variable costs of the gas-fired combined cycle could be higher depending on the price of natural gas. The starting point assumption for natural gas price is \$7.00/MMBtu.

In addition, the California CC resource incurs GHG cost exposure. This is incorporated in the analysis through the GHG adder of \$20 per ton of CO₂ as a starting point assumption. This appears in Figure 5 as a net benefit for the British Columbia wind resource, associated with the GHG adder. However, using the natural gas and GHG cost starting point assumptions of \$7.00/MMBtu and \$20/ton of CO₂ would yield a benefit-to-cost ratio of negative 0.26. This leads to a general conclusion that displacing California combined cycle with renewable energy imported over the C/PNW-NC Line is economically feasible only if natural gas price and greenhouse gas adder are sufficiently high.

As substantial additional intermittent resources are added to the grid, incremental costs are incurred to maintain the supply-demand balance of the grid, as discussed in Section 5. This cost of delivering British Columbia wind power to California appears in Figure 5 as a negative benefit associated with system integration of intermittent energy, assessed at \$3/MWh or \$48 million annually.

Finally, transmission losses are estimated to be \$6.3/MWh levelized, or \$80 million annually, in 2006 dollars¹⁵.

The benefits sum to negative \$104 million annually, in 2006 dollars. This compares to transmission cost of 400 million dollars annually, also in 2006 dollars. The result is a benefit-to-cost ratio of negative 0.26.

The costs and benefits may be summed differently, yielding a different interpretation of the same result. The incremental cost at the source is \$86.2/MWh, which is comprised of a power cost at \$76.9/MWh, system integration cost of \$3/MWh, and transmission losses of \$6.3/MWh. The incremental cost at the sink is \$78 dollars per MWh, which is comprised of a power cost at \$73.4/MWh, a GHG adder cost at \$8/MWh, and a dependable capacity cost of negative \$3.5/MWh. The resulting regional cost difference is negative \$8.2/MWh. Dividing the regional cost difference of negative \$8.2/MWh by the line cost of \$31.7/MWh yields a benefit-to-cost ratio of negative 0.26.

¹⁵ Transmission losses are captured by increasing the cost of the source resources by the percentage of transmission losses. For AC construction, the transmission line loss percentage is assumed to be 1% per 100 miles.

It is important to note that omitted from this analysis is consideration of the value of dispatchability of the combined cycle resource. The cost of producing MWh from wind is compared with the cost of producing MWh from a combined cycle. Furthermore, this analysis omits consideration of the time-differentiated value of power. Incorporating the value of dispatchability and time of delivery (TOD) into the analysis would result in a lower benefit-to-cost ratio. (TOD effects may be included through clever use of FEAST, but that is beyond the discussion in this report.) On the other hand, future grid efficiency assessments may show greater energy benefits of BC wind displacing less efficient California natural gas fired resources.

Case A2 results are displaced in Figure 6 with a benefit-to-cost ratio of 0.57. Case A2 compares British Columbia wind with California wind. Wind resource is generally viewed as a lower cost renewable resource in California. British Columbia wind is assumed to have a higher capacity factor than California wind. However, the 10% point difference assumed in the reference case only brings about a cost difference of about \$17/MWh which is slight more than half of the cost of the transmission line on a \$ per MWh basis.

Case A3 results are displaced in Figure 7 with a benefit-to-cost ratio of 1.01. Case A3 compares British Columbia wind with California concentration solar power (CSP) resources. CSP can be a major contributor to our future need for clean energy. With continued development and technology advancements, CSP are becoming competitive in the western power markets. The assumptions used here for CSP represents a high renewable renewable scenario.

Case A4 results are displaced in Figure 8 with a benefit-to-cost ratio of 0.63. Case A4 compares British Columbia wind with a mix of renewable resources in California. The mix is comprised of geothermal, solar, and wind energy on a 15/50/35 basis. This renewable resource mix represents a medium renewable cost scenario.

Case B – British Columbia Small Hydro vs. California Resources

Case B results are displayed in Figures 9 to 12. Case B1 compares small hydro resources in British Columbia to Combined Cycles in California. Case B2 compares BC small hydro with California wind. Case B3 compares BC small hydro with California CSP. Case B4 compares BC small hydro with California geothermal, CSP, and wind mix on a 15/50/35 energy basis. Similar to the analysis on British Columbia wind resources, 20% of additional small hydro capacity above the transmission line capacity was assumed. The EAC also evaluated the impact of not assuming this additional 20% wind capacity.

The reference point assumptions for British Columbia small hydro resources are at \$2,000/kW installed cost and 44% capacity factor. Using FEAST, this yields a power cost of \$69.1/MWh. Furthermore, with the 20% overbuilt assumption, the transmission line utilization factor is calculated to be 53% resulting in an average transmission line cost of \$28.8/MWh.

With a lower power cost and higher line utilization factor, the resulting benefit-to-cost ratios are higher when compared with Case A.

Case C – British Columbia Biomass vs. California Resources

Case C results are displayed in Figures 13 to 16. Case C1 compares biomass resources in British Columbia to Combined Cycles in California. Case C2 compares BC biomass with California wind. Case C3 compares BC biomass with California CSP. Case C4 compares BC biomass with California geothermal, CSP, and wind mix on a 15/50/35 energy basis.

The reference point assumptions for British Columbia biomass resources are at \$2,000/kW installed cost and 90% capacity factor. Using FEAST, this yields a power cost of \$75.6/MWh which is similar to the BC wind power cost of \$76.9/MWh and the BC small hydro power cost of \$69.1/MWh. It is important to note that the 90% capacity factor assumed for biomass resources greatly increased the transmission line's utilization factor and correspondingly decreased in a transmission line cost of \$16.9/MWh. The resulting benefit-to-cost ratios are the highest among the four set of cases.

Case D – British Columbia Renewable Mix vs. California Resources

Case D results are displayed in Figures 17 to 20. Case D assumes a mix of British Columbia renewable resources with 1,200 MW wind, 1,200 MW small hydro and 1,000 MW biomass. Using FEAST, this mix of resources yield an average power cost of \$74.1/MWh and an average capacity factor of 63%. The EAC also evaluated the impact of not assuming this additional 20% wind and hydro capacity with 1,000 MW wind, 1,000 MW small hydro and 1,000 MW biomass.

Case D1 compares this BC renewable mix with California combined cycle. Case D2 compares this BC renewable mix with California wind. Case D3 compares this BC renewable mix with California CSP. Case D4 compares this BC renewable mix with California geothermal, CSP, and wind mix on a 15/50/35 energy basis.

Figure 5

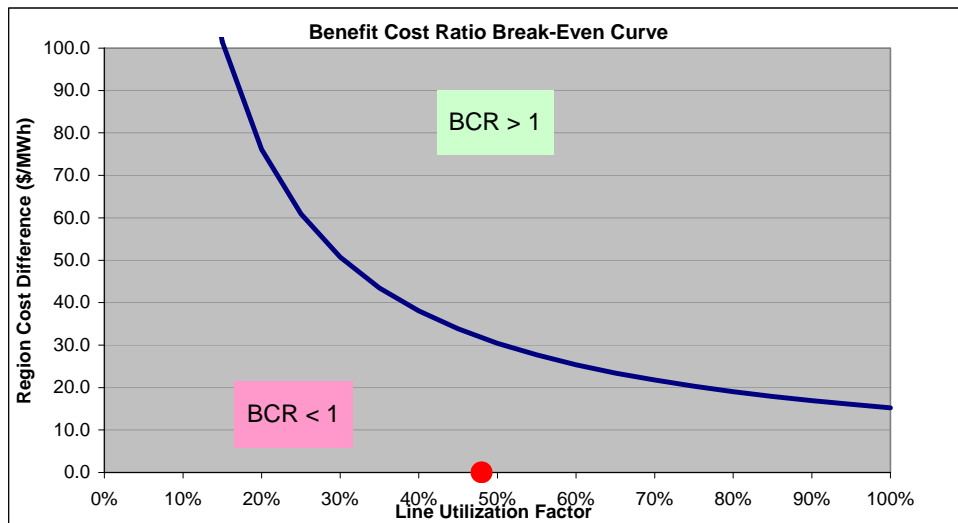
Case A1 Results

BC Wind (3,600 MW) vs. California Combined Cycle (1,846 MW)

Source: British Columbia				Sink: Northern California			
Financing	Installed Capacity (MW)	Energy (GWh)		Financing	Installed Capacity (MW)	Energy (GWh)	
Wind - BC Wind	Merchant	3,600	12,614	Combined Cycle - CA	Merchant	1,846	12,614
Hydro - BC (small)	Merchant	0	0	Wind - California	Merchant	0	0
Biomass - BC	Merchant	0	0	Solar Concen. - CA	Merchant	0	0
				Geothermal - CA	Merchant	0	0

Levelized Basis (2006 dollar-denominated)

TOTAL SYSTEM		Regional Difference		Annual Benefits (\$Million)	Annual Cost (\$Million)
Trans Option No.	1	Source (\$/MWh)	Sink (\$/MWh)		
Description		Canada 500 kV AC Double Circuit Tower Line			
Line Utilization	48%				
Installed Cost (\$Million)		4,050			
Capacity (MW)		3,000			
Line Cost (\$/MWh)	31.7	400			
Power Cost	76.9	73.4	-3.5	-44	
GHG Adder	0.0	8.0	8.0	101	
CO2 for EOR	0.0	0.0	0.0	0	
Renewable Credit	0.0	0.0	0.0	0	
System Integration	3.0	0.0	-3.0	-38	
Prod Tax Credit	0.0	0.0	0.0	0	
Losses	6.3		-6.3	-80	
Grid Eff	0.0		0.0	0	
Dependable Cap Value		-3.5	-3.5	-44	*
Winter Cap Return Value	0.0		0.0	0	**
TOTAL	86.2	78.0	-8.2	-104	400
Benefit to Cost Ratio	-0.26				



Note: Displacing California combined cycle with renewable energy imported over the C/PNW-NC Line is economically feasibility if natural gas price and greenhouse gas adder are high.

Figure 6

Case A2 Results

BC Wind (3,600 MW) vs. California Wind (4,800 MW)

Financing	Installed Capacity MW	Energy GWh
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Financing	Installed Capacity MW	Energy GWh
-----------	-----------------------	------------

Source: British Columbia

Source	Financing	Installed Capacity MW	Energy GWh
Wind - BC Wind	Merchant	3,600	12,614
Hydro - BC (small)	Merchant	0	0
Biomass - BC	Merchant	0	0

Sink: Northern California

Source	Financing	Installed Capacity MW	Energy GWh
Combined Cycle - CA	Merchant	0	0
Wind - California	Merchant	4,800	12,614
Solar Concen. - CA	Merchant	0	0
Geothermal - CA	Merchant	0	0

Levelized Basis (2006 dollar-denominated)

TOTAL SYSTEM

Trans Option No.	1	Installed Cost (\$Million)	4,050
		Capacity (MW)	3,000
Description	Canada 500 kV AC Double Circuit Tower Line		
Line Utilization	48%		

	(\$/MWh)	Regional Difference			Annual Benefits (\$Million)	Annual Cost (\$Million)
		Source (\$/MWh)	Sink (\$/MWh)	Diff (\$/MWh)		
Line Cost	31.7				400	
Power Cost		76.9	100.7	23.8	300	
GHG Adder		0.0	0.0	0.0	0	
CO2 for EOR		0.0	0.0	0.0	0	
Renewable Credit		0.0	0.0	0.0	0	
System Integration		3.0	3.0	0.0	0	
Prod Tax Credit		0.0	0.0	0.0	0	
Losses		6.3		-6.3	-80	
Grid Eff		0.0		0.0	0	
Dependable Cap Value			-0.8	-0.8	-10	
Winter Cap Return Value		0.0		0.0	0	
TOTAL		86.2	102.9	16.7	211	
Benefit to Cost Ratio	0.53				400	

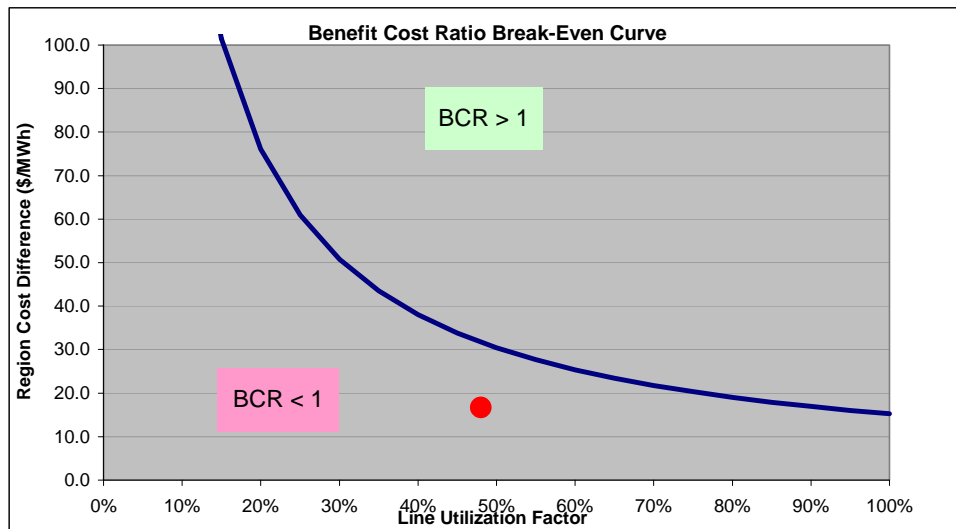


Figure 7

Case A3 Results

BC Wind (3,600 MW) vs. California Solar (3,564 MW)

Financing	Installed Capacity MW	Energy GWh
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Financing	Installed Capacity MW	Energy GWh
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Source: British Columbia

Source	Financing	Installed Capacity MW	Energy GWh
Wind - BC Wind	Merchant	3,600	12,614
Hydro - BC (small)	Merchant	0	0
Biomass - BC	Merchant	0	0

Sink: Northern California

Source	Financing	Installed Capacity MW	Energy GWh
Combined Cycle - CA	Merchant	0	0
Wind - California	Merchant	0	0
Solar Concen. - CA	Merchant	3,564	12,614
Geothermal - CA	Merchant	0	0

Levelized Basis (2006 dollar-denominated)

TOTAL SYSTEM

Trans Option No.	1	Installed Cost (\$Million)	4,050
		Capacity (MW)	3,000
Description	Canada 500 kV AC Double Circuit Tower Line		
Line Utilization	48%		

	(\$/MWh)	Regional Difference			Annual Benefits (\$Million)	Annual Cost (\$Million)
		Source (\$/MWh)	Sink (\$/MWh)	Diff (\$/MWh)		
Line Cost	31.7					400
Power Cost		76.9	125.8	48.8	616	
GHG Adder		0.0	0.0	0.0	0	
CO2 for EOR		0.0	0.0	0.0	0	
Renewable Credit		0.0	0.0	0.0	0	
System Integration		3.0	0.0	-3.0	-38	
Prod Tax Credit		0.0	0.0	0.0	0	
Losses		6.3		-6.3	-80	
Grid Eff		0.0		0.0	0	
Dependable Cap Value			-7.4	-7.4	-94	*
Winter Cap Return Value		0.0		0.0	0	**
TOTAL		86.2	118.3	32.1	405	400
Benefit to Cost Ratio	1.01					

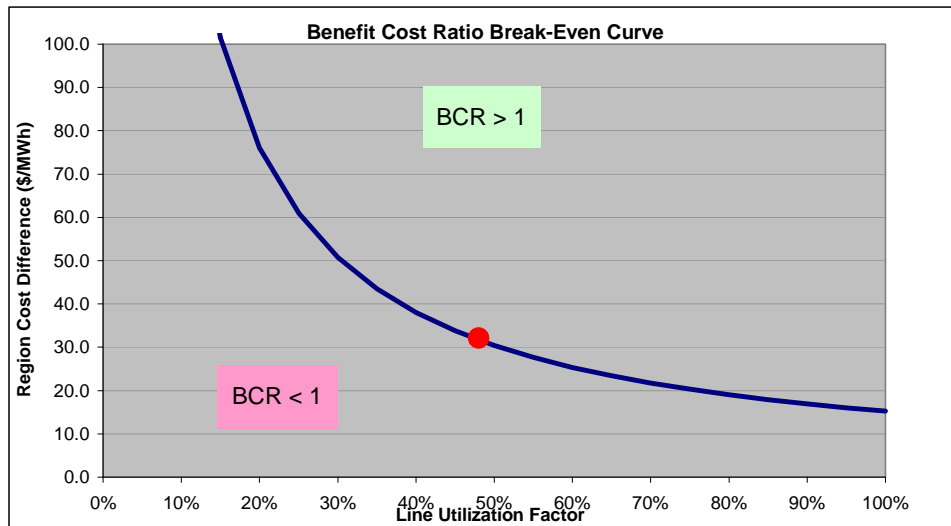


Figure 8

Case A4 Results

BC Wind (3600 MW) vs. California Renewable Mix

Financing	Installed Capacity MW	Energy GWh
-----------	-----------------------	------------

Financing	Installed Capacity MW	Energy GWh
-----------	-----------------------	------------

Source: British Columbia

Source	Financing	Installed Capacity MW	Energy GWh
Wind - BC Wind	Merchant	3,600	12,614
Hydro - BC (small)	Merchant	0	0
Biomass - BC	Merchant	0	0

Sink: Northern California

Source	Financing	Installed Capacity MW	Energy GWh
Combined Cycle - CA	Merchant	0	0
Wind - California	Merchant	1,680	4,415
Solar Concen. - CA	Merchant	1,785	6,317
Geothermal - CA	Merchant	226	1,882

Levelized Basis (2006 dollar-denominated)

TOTAL SYSTEM

Trans Option No.	1	Installed Cost (\$Million)	4,050
		Capacity (MW)	3,000
Description	Canada 500 kV AC Double Circuit Tower Line		
Line Utilization	48%		

	(\$/MWh)	Regional Difference			Annual Benefits (\$Million)	Annual Cost (\$Million)
		Source (\$/MWh)	Sink (\$/MWh)	Diff (\$/MWh)		
Line Cost	31.7					400
Power Cost		76.9	109.6	32.7	413	
GHG Adder		0.0	0.0	0.0	0	
CO2 for EOR		0.0	0.0	0.0	0	
Renewable Credit		0.0	0.0	0.0	0	
System Integration		3.0	1.1	-1.9	-25	
Prod Tax Credit		0.0	0.0	0.0	0	
Losses		6.3		-6.3	-80	
Grid Eff		0.0		0.0	0	
Dependable Cap Value			-4.4	-4.4	-55	*
Winter Cap Return Value		0.0		0.0	0	**
TOTAL		86.2	106.3	20.1	253	400
Benefit to Cost Ratio	0.63					

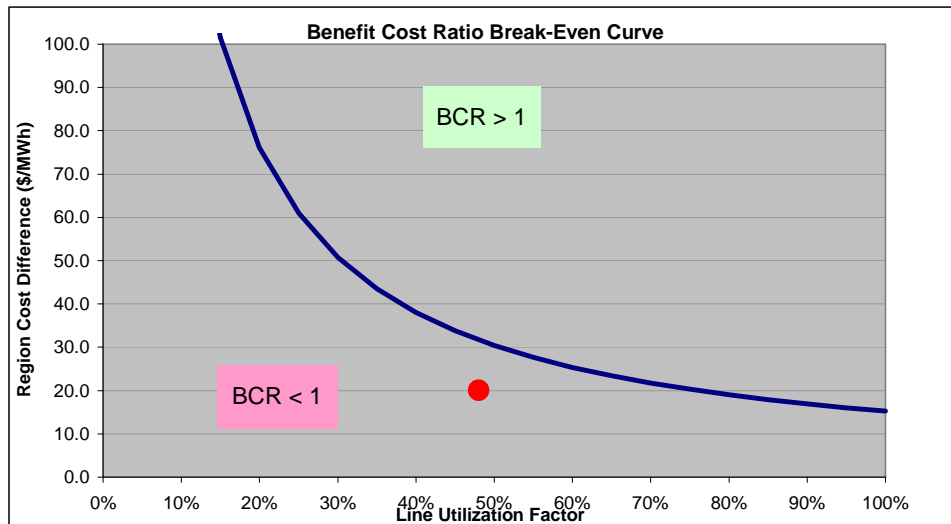


Figure 9 Case B1 Results

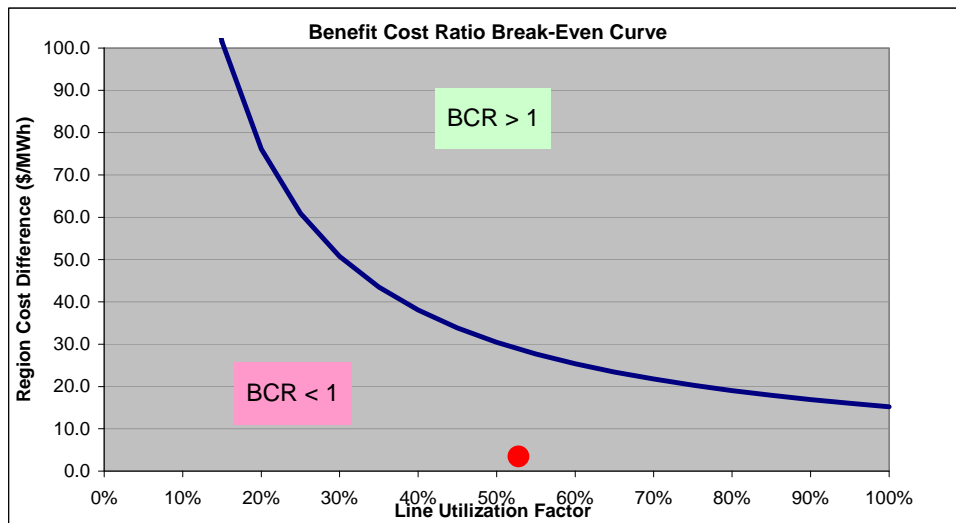
BC Small Hydro (3600 MW) vs. California Combined Cycle (2031 MW)

Source: British Columbia				Sink: Northern California			
	Financing	Installed Capacity MW	Energy GWh		Financing	Installed Capacity MW	Energy GWh
Wind - BC Wind	Merchant	0	0	Combined Cycle - CA	Merchant	2,031	13,876
Hydro - BC (small)	Merchant	3,600	13,876	Wind - California	Merchant	0	0
Biomass - BC	Merchant	0	0	Solar Concen. - CA	Merchant	0	0
				Geothermal - CA	Merchant	0	0

Levelized Basis (2006 dollar-denominated)

TOTAL SYSTEM			
Trans Option No.	1	Installed Cost (\$Million)	4,050
		Capacity (MW)	3,000
Description	Canada 500 kV AC Double Circuit Tower Line		
Line Utilization	53%		

	(\$/MWh)	Regional Difference			Annual Benefits (\$Million)	Annual Cost (\$Million)
		Source (\$/MWh)	Sink (\$/MWh)	Diff (\$/MWh)		
Line Cost	28.8					400
Power Cost		69.1	73.4	4.4	61	
GHG Adder		0.0	8.0	8.0	111	
CO2 for EOR		0.0	0.0	0.0	0	
Renewable Credit		0.0	0.0	0.0	0	
System Integration		0.0	0.0	0.0	0	
Prod Tax Credit		0.0	0.0	0.0	0	
Losses		5.7		-5.7	-79	
Grid Eff		0.0		0.0	0	
Dependable Cap Value			-3.3	-3.3	-45	*
Winter Cap Return Value		0.0		0.0	0	**
TOTAL		74.7	78.2	3.5	48	400
Benefit to Cost Ratio	0.12					



Note: Displacing California combined cycle with renewable energy imported over the C/PNW-NC Line is economically feasibility if natural gas price and greenhouse gas adder are high.

Figure 10
Case B2 Results

BC Small Hydro (3600 MW) vs. California Wind (5280 MW)

Source: British Columbia				Sink: Northern California			
Financing	Installed Capacity MW	Energy GWh		Financing	Installed Capacity MW	Energy GWh	
Wind - BC Wind	Merchant	0	0	Combined Cycle - CA	Merchant	0	0
Hydro - BC (small)	Merchant	3,600	13,876	Wind - California	Merchant	5,280	13,876
Biomass - BC	Merchant	0	0	Solar Concen. - CA	Merchant	0	0
				Geothermal - CA	Merchant	0	0

Levelized Basis (2006 dollar-denominated)

TOTAL SYSTEM

Trans Option No.	1	Installed Cost (\$Million)	4,050
		Capacity (MW)	3,000
Description	Canada 500 kV AC Double Circuit Tower Line		
Line Utilization	53%		

	(\$/MWh)	Regional Difference			Annual Benefits (\$Million)	Annual Cost (\$Million)
		Source (\$/MWh)	Sink (\$/MWh)	Diff (\$/MWh)		
Line Cost	28.8					400
Power Cost		69.1	100.7	31.7	439	
GHG Adder		0.0	0.0	0.0	0	
CO2 for EOR		0.0	0.0	0.0	0	
Renewable Credit		0.0	0.0	0.0	0	
System Integration		0.0	3.0	3.0	42	
Prod Tax Credit		0.0	0.0	0.0	0	
Losses		5.7		-5.7	-79	
Grid Eff		0.0		0.0	0	
Dependable Cap Value			-0.6	-0.6	-8	*
Winter Cap Return Value		0.0		0.0	0	**
TOTAL		74.7	103.1	28.4	394	400
Benefit to Cost Ratio	0.99					

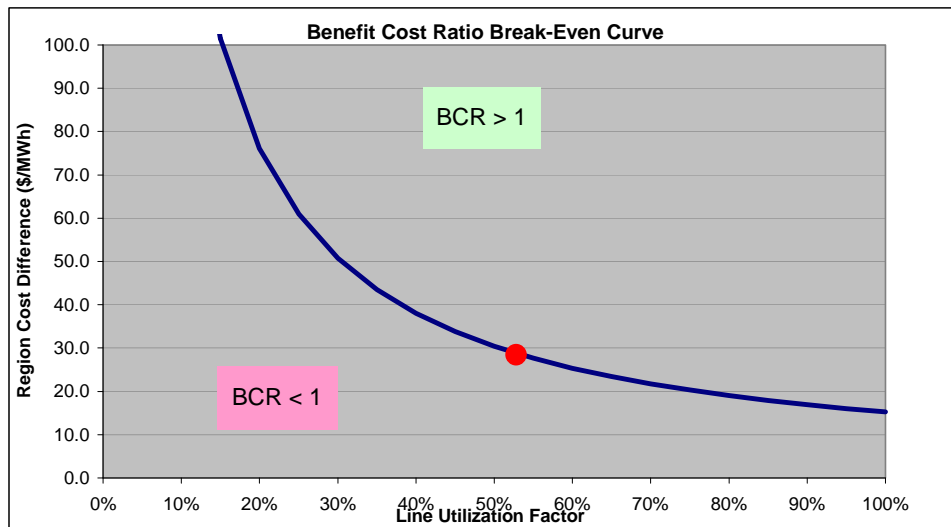


Figure 11 Case B3 Results

BC Small Hydro (3600 MW) vs. California Solar (3921 MW)

Source: British Columbia				Sink: Northern California			
Financing	Installed Capacity MW	Energy GWh		Financing	Installed Capacity MW	Energy GWh	
Wind - BC Wind	Merchant	0	0	Combined Cycle - CA	Merchant	0	0
Hydro - BC (small)	Merchant	3,600	13,876	Wind - California	Merchant	0	0
Biomass - BC	Merchant	0	0	Solar Concen. - CA	Merchant	3,921	13,876
				Geothermal - CA	Merchant	0	0

Levelized Basis (2006 dollar-denominated)

TOTAL SYSTEM			
Trans Option No.	1	Installed Cost (\$Million)	4,050
		Capacity (MW)	3,000
Description	Canada 500 kV AC Double Circuit Tower Line		
Line Utilization	53%		

	(\$/MWh)	Regional Difference			Annual Benefits (\$Million)	Annual Cost (\$Million)
		Source (\$/MWh)	Sink (\$/MWh)	Diff (\$/MWh)		
Line Cost	28.8					400
Power Cost		69.1	125.8	56.7	787	
GHG Adder		0.0	0.0	0.0	0	
CO2 for EOR		0.0	0.0	0.0	0	
Renewable Credit		0.0	0.0	0.0	0	
System Integration		0.0	0.0	0.0	0	
Prod Tax Credit		0.0	0.0	0.0	0	
Losses		5.7		-5.7	-79	
Grid Eff		0.0		0.0	0	
Dependable Cap Value			-7.2	-7.2	-100	*
Winter Cap Return Value		0.0		0.0	0	**
TOTAL		74.7	118.5	43.8	608	400
Benefit to Cost Ratio	1.52					

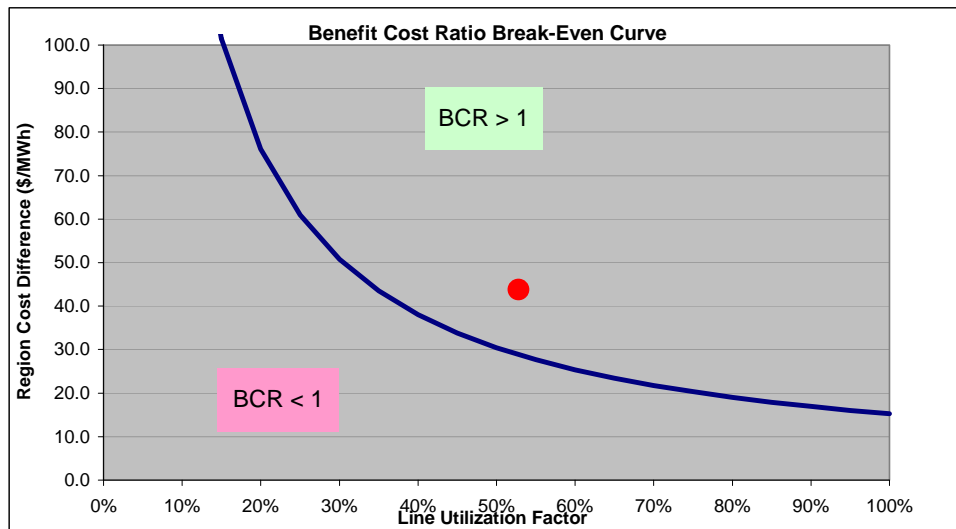


Figure 12 Case B4 Results

BC Small Hydro (3600 MW) vs. California Renewable Mix

Source: British Columbia				Sink: Northern California			
	Financing	Installed Capacity MW	Energy GWh		Financing	Installed Capacity MW	Energy GWh
Wind - BC Wind	Merchant	0	0	Combined Cycle - CA	Merchant	0	0
Hydro - BC (small)	Merchant	3,600	13,876	Wind - California	Merchant	1,845	4,848
Biomass - BC	Merchant	0	0	Solar Concen. - CA	Merchant	1,965	6,952
				Geothermal - CA	Merchant	250	2,076

Levelized Basis (2006 dollar-denominated)

TOTAL SYSTEM		Installed Cost (\$Million)		Capacity (MW)	
Trans Option No.	1			4,050	
				3,000	
Description	Canada 500 kV AC Double Circuit Tower Line				
Line Utilization	53%				

	(\$/MWh)	Regional Difference			Annual Benefits (\$Million)	Annual Cost (\$Million)
		Source (\$/MWh)	Sink (\$/MWh)	Diff (\$/MWh)		
Line Cost	28.8					400
Power Cost		69.1	109.6	40.6	563	
GHG Adder		0.0	0.0	0.0	0	
CO2 for EOR		0.0	0.0	0.0	0	
Renewable Credit		0.0	0.0	0.0	0	
System Integration		0.0	1.0	1.0	15	
Prod Tax Credit		0.0	0.0	0.0	0	
Losses		5.7		-5.7	-79	
Grid Eff		0.0		0.0	0	
Dependable Cap Value			-4.2	-4.2	-58	*
Winter Cap Return Value		0.0		0.0	0	**
TOTAL		74.7	106.5	31.8	441	400
Benefit to Cost Ratio	1.10					

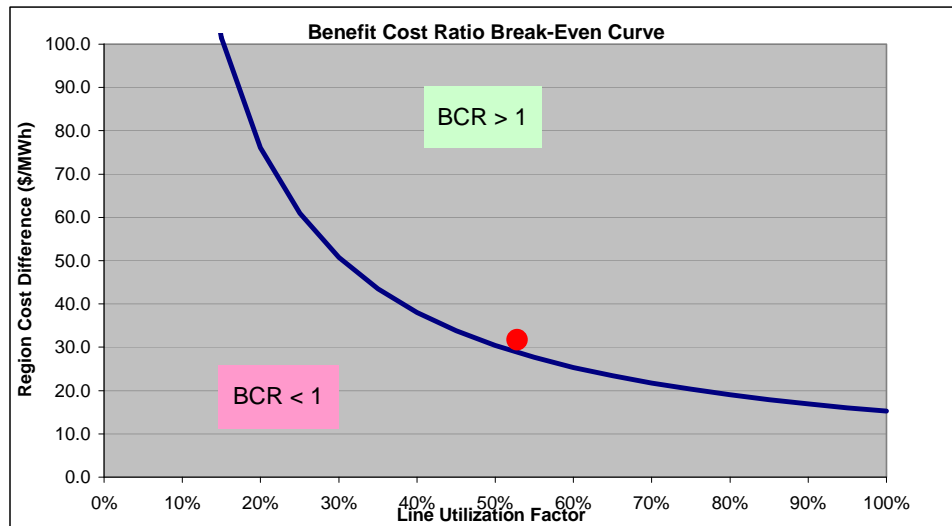


Figure 13 Case C1 Results

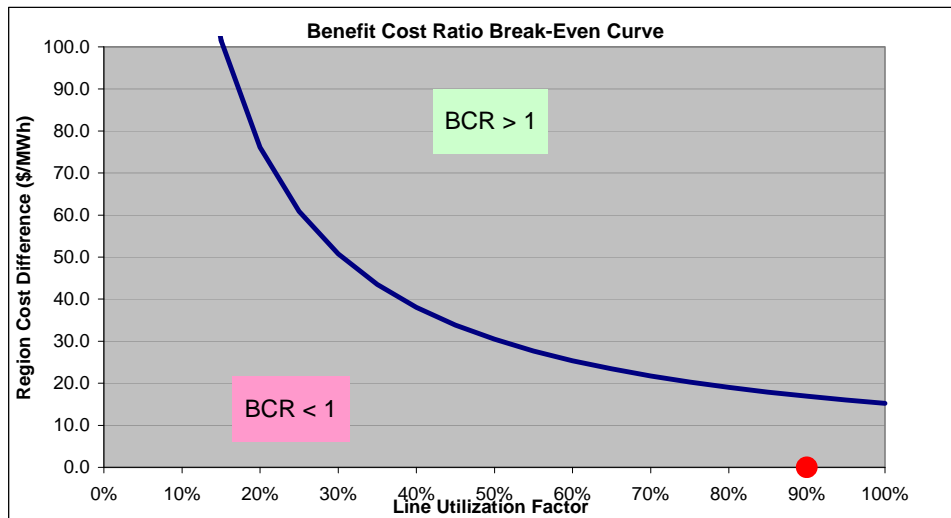
BC Biomass (3,000 MW) vs. California Combined Cycle (3,462 MW)

Source: British Columbia				Sink: Northern California			
Financing	Installed Capacity MW	Energy GWh		Financing	Installed Capacity MW	Energy GWh	
Wind - BC Wind	Merchant	0	0	Combined Cycle - CA	Merchant	3,462	23,652
Hydro - BC (small)	Merchant	0	0	Wind - California	Merchant	0	0
Biomass - BC	Merchant	3,000	23,652	Solar Concen. - CA	Merchant	0	0
				Geothermal - CA	Merchant	0	0

Levelized Basis (2006 dollar-denominated)

TOTAL SYSTEM	
Trans Option No.	1
Installed Cost (\$Million)	4,050
Capacity (MW)	3,000
Description	Canada 500 kV AC Double Circuit Tower Line
Line Utilization	90%

	(\$/MWh)	Regional Difference			Annual Benefits (\$Million)	Annual Cost (\$Million)
		Source (\$/MWh)	Sink (\$/MWh)	Diff (\$/MWh)		
Line Cost	16.9					400
Power Cost		75.6	73.4	-2.2	-52	
GHG Adder		0.0	8.0	8.0	189	
CO2 for EOR		0.0	0.0	0.0	0	
Renewable Credit		0.0	0.0	0.0	0	
System Integration		0.0	0.0	0.0	0	
Prod Tax Credit		0.0	0.0	0.0	0	
Losses		6.2		-6.2	-147	
Grid Eff		0.0		0.0	0	
Dependable Cap Value			-0.8	-0.8	-18	*
Winter Cap Return Value		0.0		0.0	0	**
TOTAL		81.9	80.7	-1.2	-28	400
Benefit to Cost Ratio	-0.07					



Note: Displacing California combined cycle with renewable energy imported over the C/PNW-NC Line is economically feasibility if natural gas price and greenhouse gas adder are high.

Figure 14 Case C2 Results

BC Biomass (3,000 MW) vs. California Wind (9,000 MW)

Financing	Installed Capacity MW	Energy GWh
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Financing	Installed Capacity MW	Energy GWh
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Source: British Columbia

Source	Merchant	Capacity (MW)	Energy (GWh)
Wind - BC Wind	Merchant	0	0
Hydro - BC (small)	Merchant	0	0
Biomass - BC	Merchant	3,000	23,652

Sink: Northern California

Source	Merchant	Capacity (MW)	Energy (GWh)
Combined Cycle - CA	Merchant	0	0
Wind - California	Merchant	9,000	23,652
Solar Concen. - CA	Merchant	0	0
Geothermal - CA	Merchant	0	0

Levelized Basis (2006 dollar-denominated)

TOTAL SYSTEM

Trans Option No.	1	Installed Cost (\$Million)	4,050
		Capacity (MW)	3,000
Description	Canada 500 kV AC Double Circuit Tower Line		
Line Utilization	90%		

	(\$/MWh)	Regional Difference			Annual Benefits (\$Million)	Annual Cost (\$Million)
		Source (\$/MWh)	Sink (\$/MWh)	Diff (\$/MWh)		
Line Cost	16.9					400
Power Cost		75.6	100.7	25.1	593	
GHG Adder		0.0	0.0	0.0	0	
CO2 for EOR		0.0	0.0	0.0	0	
Renewable Credit		0.0	0.0	0.0	0	
System Integration		0.0	3.0	3.0	71	
Prod Tax Credit		0.0	0.0	0.0	0	
Losses		6.2		-6.2	-147	
Grid Eff		0.0		0.0	0	
Dependable Cap Value			1.9	1.9	44	*
Winter Cap Return Value		0.0		0.0	0	**
TOTAL		81.9	105.6	23.8	562	400
Benefit to Cost Ratio	1.40					

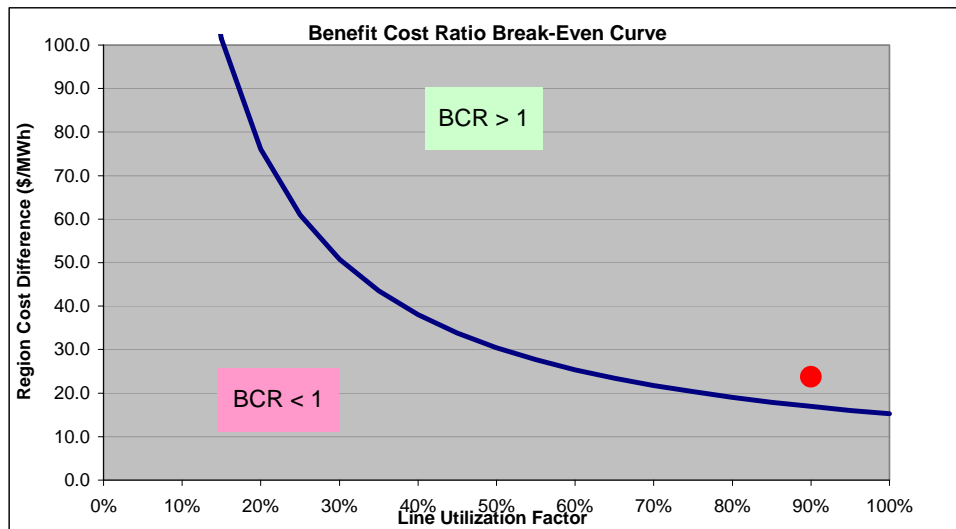


Figure 15 Case C3 Results

BC Biomass (3,000 MW) vs. California Solar (6,683 MW)

Financing	Installed Capacity MW	Energy GWh
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Financing	Installed Capacity MW	Energy GWh
-----------	-----------------------	------------

Source: British Columbia

Source	Financing	Installed Capacity MW	Energy GWh
Wind - BC Wind	Merchant	0	0
Hydro - BC (small)	Merchant	0	0
Biomass - BC	Merchant	3,000	23,652

Sink: Northern California

Source	Financing	Installed Capacity MW	Energy GWh
Combined Cycle - CA	Merchant	0	0
Wind - California	Merchant	0	0
Solar Concen. - CA	Merchant	6,683	23,652
Geothermal - CA	Merchant	0	0

Levelized Basis (2006 dollar-denominated)

TOTAL SYSTEM

Trans Option No.	1	Installed Cost (\$Million)	4,050
		Capacity (MW)	3,000
Description	Canada 500 kV AC Double Circuit Tower Line		
Line Utilization	90%		

	(\$/MWh)	Regional Difference			Annual Benefits (\$Million)	Annual Cost (\$Million)
		Source (\$/MWh)	Sink (\$/MWh)	Diff (\$/MWh)		
Line Cost	16.9					400
Power Cost		75.6	125.8	50.1	1,185	
GHG Adder		0.0	0.0	0.0	0	
CO2 for EOR		0.0	0.0	0.0	0	
Renewable Credit		0.0	0.0	0.0	0	
System Integration		0.0	0.0	0.0	0	
Prod Tax Credit		0.0	0.0	0.0	0	
Losses		6.2		-6.2	-147	
Grid Eff		0.0		0.0	0	
Dependable Cap Value			-4.8	-4.8	-113	*
Winter Cap Return Value		0.0		0.0	0	**
TOTAL		81.9	121.0	39.1	926	400
Benefit to Cost Ratio	2.31					

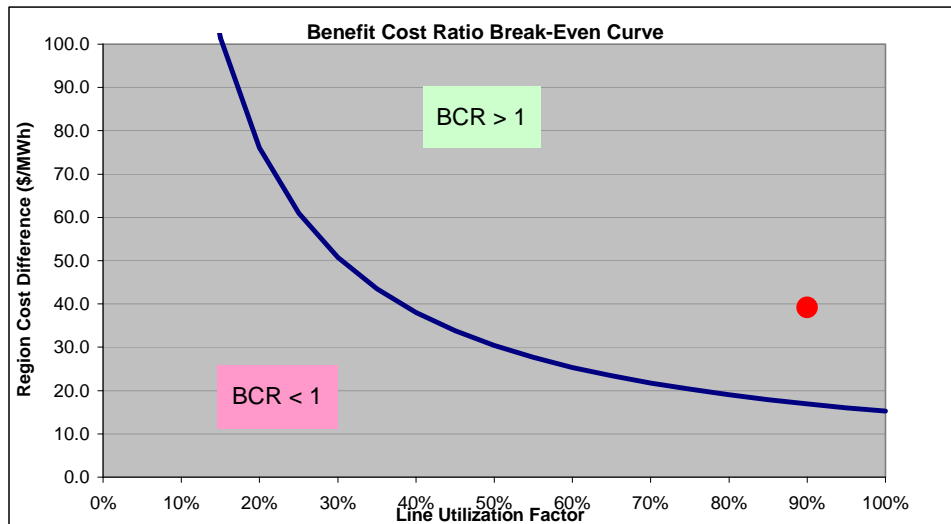


Figure 16 Case C4 Results

BC Biomass (3,000 MW) vs. California Renewable Mix

Source: British Columbia				Sink: Northern California			
Financing	Installed Capacity (MW)	Energy (GWh)		Financing	Installed Capacity (MW)	Energy (GWh)	
Wind - BC Wind	Merchant	0	0	Combined Cycle - CA	Merchant	0	0
Hydro - BC (small)	Merchant	0	0	Wind - California	Merchant	3,150	8,278
Biomass - BC	Merchant	3,000	23,652	Solar Concen. - CA	Merchant	3,345	11,837
				Geothermal - CA	Merchant	425	3,537

Levelized Basis (2006 dollar-denominated)

TOTAL SYSTEM			
Trans Option No.	1	Installed Cost (\$Million)	4,050
		Capacity (MW)	3,000
Description	Canada 500 kV AC Double Circuit Tower Line		
Line Utilization	90%		

	(\$/MWh)	Regional Difference			Annual Benefits (\$Million)	Annual Cost (\$Million)
		Source (\$/MWh)	Sink (\$/MWh)	Diff (\$/MWh)		
Line Cost	16.9				400	
Power Cost		75.6	109.6	34.0	803	
GHG Adder		0.0	0.0	0.0	0	
CO2 for EOR		0.0	0.0	0.0	0	
Renewable Credit		0.0	0.0	0.0	0	
System Integration		0.0	1.0	1.0	25	
Prod Tax Credit		0.0	0.0	0.0	0	
Losses		6.2		-6.2	-147	
Grid Eff		0.0		0.0	0	
Dependable Cap Value			-1.7	-1.7	-40	
Winter Cap Return Value		0.0		0.0	0	
TOTAL		81.9	109.0	27.1	642	
Benefit to Cost Ratio	1.60				400	

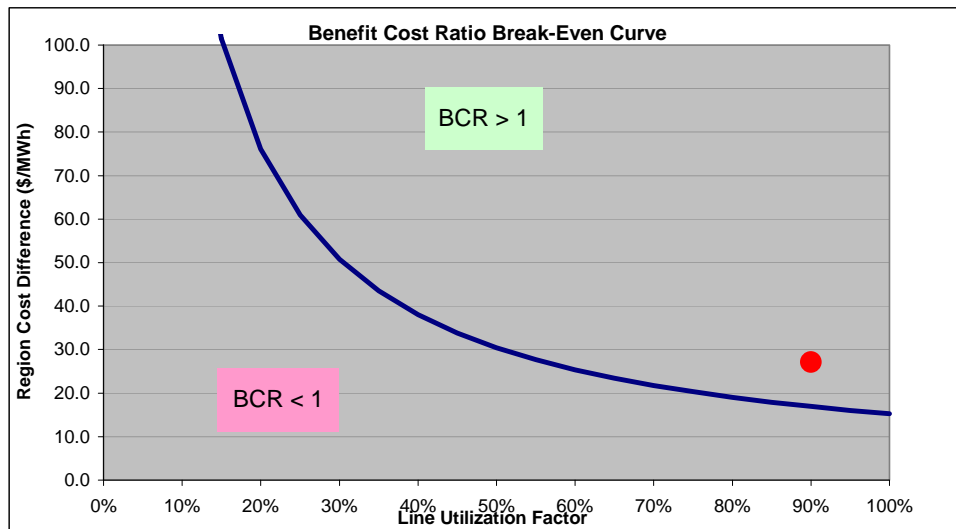


Figure 17 Case D1 Results

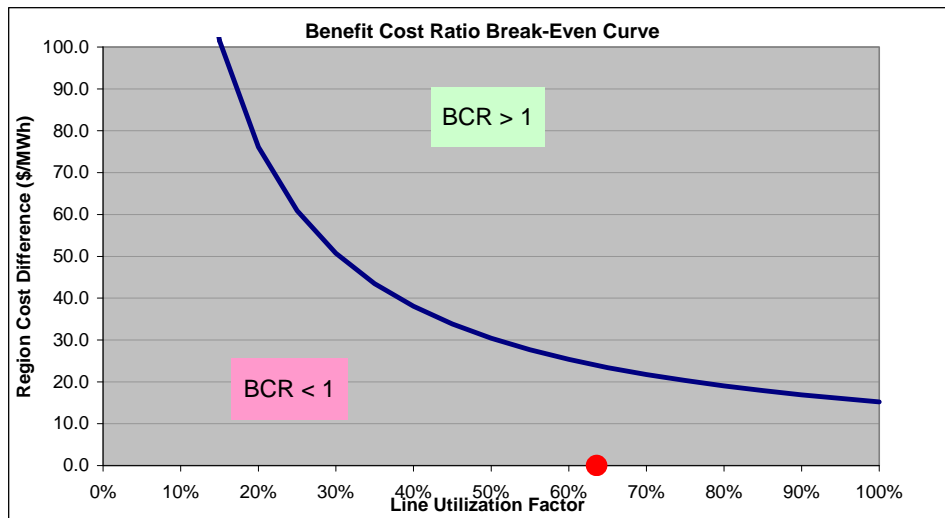
BC Renewable Mix vs. California Combined Cycle (2,446 MW)

Source: British Columbia				Sink: Northern California			
	Financing	Installed Capacity MW	Energy GWh		Financing	Installed Capacity MW	Energy GWh
Wind - BC Wind	Merchant	1,200	4,205	Combined Cycle - CA	Merchant	2,446	16,714
Hydro - BC (small)	Merchant	1,200	4,625	Wind - California	Merchant	0	0
Biomass - BC	Merchant	1,000	7,884	Solar Concen. - CA	Merchant	0	0
				Geothermal - CA	Merchant	0	0

Levelized Basis (2006 dollar-denominated)

TOTAL SYSTEM			
Trans Option No.	1	Installed Cost (\$Million)	4,050
		Capacity (MW)	3,000
Description	Canada 500 kV AC Double Circuit Tower Line		
Line Utilization	64%		

	(\$/MWh)	Regional Difference			Annual Benefits (\$Million)	Annual Cost (\$Million)
		Source (\$/MWh)	Sink (\$/MWh)	Diff (\$/MWh)		
Line Cost	23.9					400
Power Cost		74.1	73.4	-0.7	-12	
GHG Adder		0.0	8.0	8.0	134	
CO2 for EOR		0.0	0.0	0.0	0	
Renewable Credit		0.0	0.0	0.0	0	
System Integration		0.8	0.0	-0.8	-13	
Prod Tax Credit		0.0	0.0	0.0	0	
Losses		6.1		-6.1	-102	
Grid Eff		0.0		0.0	0	
Dependable Cap Value			-2.1	-2.1	-36	*
Winter Cap Return Value		0.0		0.0	0	**
TOTAL		81.0	79.3	-1.7	-28	400
Benefit to Cost Ratio	-0.07					



Note: Displacing California combined cycle with renewable energy imported over the C/PNW-NC Line is economically feasibility if natural gas price and greenhouse gas adder are high.

Figure 18 Case D2 Results

BC Renewable Mix vs. California Wind (6,360 MW)

Financing	Installed Capacity MW	Energy GWh
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Financing	Installed Capacity MW	Energy GWh
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Source: British Columbia

Source	Financing	Installed Capacity MW	Energy GWh
Wind - BC Wind	Merchant	1,200	4,205
Hydro - BC (small)	Merchant	1,200	4,625
Biomass - BC	Merchant	1,000	7,884

Sink: Northern California

Source	Financing	Installed Capacity MW	Energy GWh
Combined Cycle - CA	Merchant	0	0
Wind - California	Merchant	6,360	16,714
Solar Concen. - CA	Merchant	0	0
Geothermal - CA	Merchant	0	0

Levelized Basis (2006 dollar-denominated)

TOTAL SYSTEM

Trans Option No.	1	Installed Cost (\$Million)	4,050
		Capacity (MW)	3,000
Description	Canada 500 kV AC Double Circuit Tower Line		
Line Utilization	64%		

	(\$/MWh)	Regional Difference			Annual Benefits (\$Million)	Annual Cost (\$Million)
		Source (\$/MWh)	Sink (\$/MWh)	Diff (\$/MWh)		
Line Cost	23.9				400	
Power Cost		74.1	100.7	26.6	444	
GHG Adder		0.0	0.0	0.0	0	
CO2 for EOR		0.0	0.0	0.0	0	
Renewable Credit		0.0	0.0	0.0	0	
System Integration		0.8	3.0	2.2	38	
Prod Tax Credit		0.0	0.0	0.0	0	
Losses		6.1		-6.1	-102	
Grid Eff		0.0		0.0	0	
Dependable Cap Value			0.5	0.5	9	
Winter Cap Return Value		0.0		0.0	0	
TOTAL		81.0	104.3	23.3	389	
Benefit to Cost Ratio	0.97					

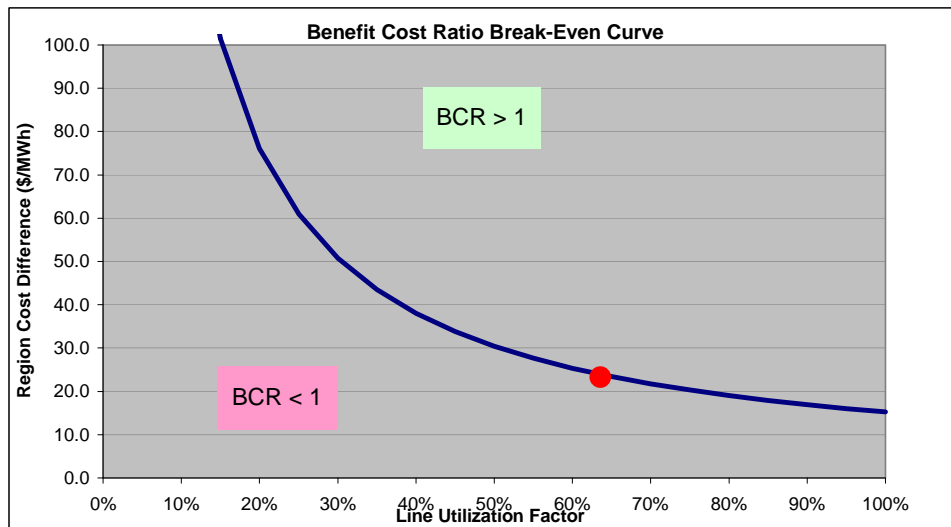


Figure 19 Case D3 Results

BC Renewable Mix vs. California Solar (4,723 MW)

Source: British Columbia				Sink: Northern California			
	Financing	Installed Capacity MW	Energy GWh		Financing	Installed Capacity MW	Energy GWh
Wind - BC Wind	Merchant	1,200	4,205	Combined Cycle - CA	Merchant	0	0
Hydro - BC (small)	Merchant	1,200	4,625	Wind - California	Merchant	0	0
Biomass - BC	Merchant	1,000	7,884	Solar Concen. - CA	Merchant	4,723	16,714
				Geothermal - CA	Merchant	0	0

Levelized Basis (2006 dollar-denominated)

TOTAL SYSTEM			
Trans Option No.	1	Installed Cost (\$Million)	4,050
		Capacity (MW)	3,000
Description	Canada 500 kV AC Double Circuit Tower Line		
Line Utilization	64%		

	(\$/MWh)	Regional Difference			Annual Benefits (\$Million)	Annual Cost (\$Million)
		Source (\$/MWh)	Sink (\$/MWh)	Diff (\$/MWh)		
Line Cost	23.9					400
Power Cost		74.1	125.8	51.6	863	
GHG Adder		0.0	0.0	0.0	0	
CO2 for EOR		0.0	0.0	0.0	0	
Renewable Credit		0.0	0.0	0.0	0	
System Integration		0.8	0.0	-0.8	-13	
Prod Tax Credit		0.0	0.0	0.0	0	
Losses		6.1		-6.1	-102	
Grid Eff		0.0		0.0	0	
Dependable Cap Value			-6.1	-6.1	-102	*
Winter Cap Return Value		0.0		0.0	0	**
TOTAL		81.0	119.6	38.6	646	400
Benefit to Cost Ratio	1.61					

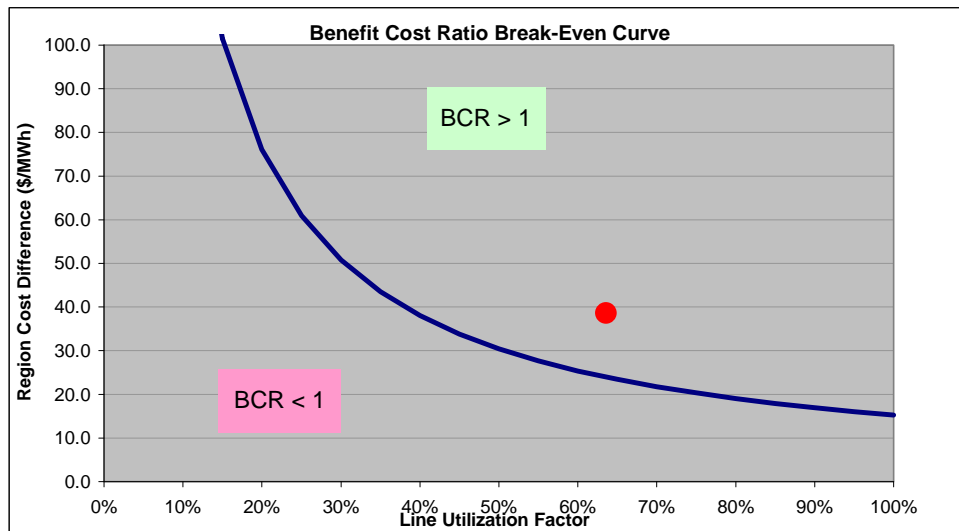


Figure 20 Case D4 Results

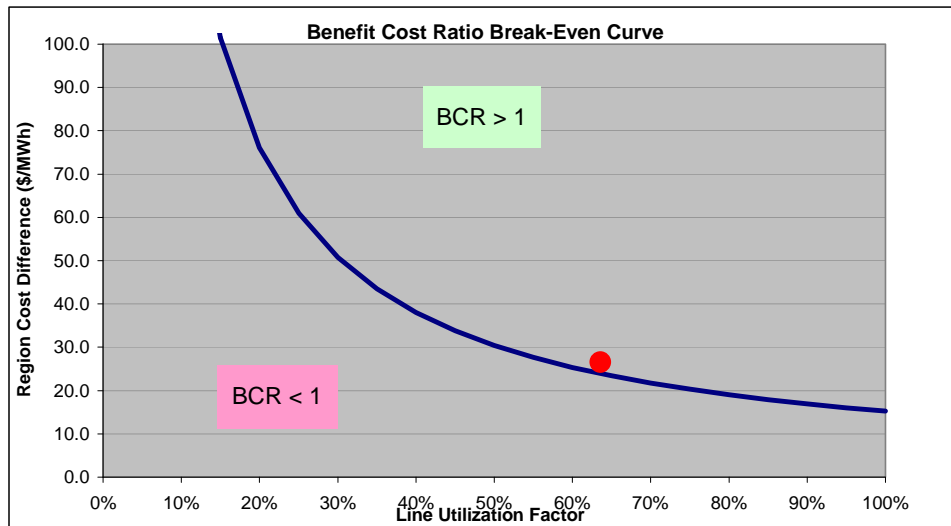
BC Renewable Mix vs. California Renewable Mix

Source: British Columbia				Sink: Northern California			
	Financing	Installed Capacity MW	Energy GWh		Financing	Installed Capacity MW	Energy GWh
Wind - BC Wind	Merchant	1,200	4,205	Combined Cycle - CA	Merchant	0	0
Hydro - BC (small)	Merchant	1,200	4,625	Wind - California	Merchant	2,225	5,847
Biomass - BC	Merchant	1,000	7,884	Solar Concen. - CA	Merchant	2,355	8,334
				Geothermal - CA	Merchant	304	2,532

Levelized Basis (2006 dollar-denominated)

TOTAL SYSTEM			
Trans Option No.	1	Installed Cost (\$Million)	4,050
		Capacity (MW)	3,000
Description	Canada 500 kV AC Double Circuit Tower Line		
Line Utilization	64%		

	(\$/MWh)	Regional Difference			Annual Benefits (\$Million)	Annual Cost (\$Million)
		Source (\$/MWh)	Sink (\$/MWh)	Diff (\$/MWh)		
Line Cost	23.9					400
Power Cost		74.1	109.5	35.4	591	
GHG Adder		0.0	0.0	0.0	0	
CO2 for EOR		0.0	0.0	0.0	0	
Renewable Credit		0.0	0.0	0.0	0	
System Integration		0.8	1.0	0.3	5	
Prod Tax Credit		0.0	0.0	0.0	0	
Losses		6.1		-6.1	-102	
Grid Eff		0.0		0.0	0	
Dependable Cap Value			-3.0	-3.0	-51	*
Winter Cap Return Value		0.0		0.0	0	**
TOTAL		81.0	107.5	26.5	444	400
Benefit to Cost Ratio	1.11					



Sensitivities

At the outset, before any analysis was performed, the Economic Analysis Committee identified critical uncertainties that would drive results. Commodity prices and technology costs and performance assumptions were identified as critical uncertainties. Thus, sensitivities were performed on natural gas price, value of the GHG adder, installed costs for wind, small hydro and concentrating solar power resources, and their capacity factor assumptions. As the Economic Analysis Committee performed its analyses, the Committee also identified the cost of the C/PNW-NC line, and the potential of grid efficiency improvement and seasonal energy exchange as additional uncertainties worth investigating. This section presents some of the sensitivity analyses performed by the Economic Analysis Committee.

Natural Gas Price

Cases A1, B1, C1 and D1 compare British Columbia resources with California combined cycle resources. The power production cost of the California CC is highly sensitive to natural gas prices. Figure 21 displays how the benefit-to-cost ratio changes as natural gas prices change using Case B1 as an example. The horizontal axis indicates values for natural gas price from \$4.00 to \$10.00 per MMBtu (levelized for the period 2015-2034, in 2006 US dollars), the suggested natural gas price range. The vertical axis indicates the benefit-to-cost ratio. The blue line plots how benefit-to-cost ratio varies with natural gas price. The red dot indicates the case results using the reference set value of \$7.00/MMBtu. The horizontal green line represents benefit-to-cost ratio at 1.0.

As anticipated, the benefit-to-cost ratio increases as natural gas price increases. The slope of the blue line is quite steep. As natural gas price increases, the C/PNW-NC Line appears more beneficial when the displaced generation in California is natural gas-fired resources.

Figure 22 displays, for Case C1, how benefit-to-cost ratio changes as natural gas prices change. The slope of the blue line is even steeper than it is in Case A1, largely because more MWs of gas-fired CC are in the California incremental mix.

GHG Adder

Similar to the figures for natural gas price sensitivity, Figures 23 and 24 displays for Cases A1 and C1, how the benefit-to-cost ratio changes as the value of the GHG adder changes. Higher GHG adder is associated with more costs for the California resources when the displaced generation in California is natural gas-fired resources. The slope of the blue lines is somewhat steep. As GHG adder increases, the C/PNW-NC Line appears more beneficial.

GHG Adder and Natural Gas Price

Figure 25 puts both GHG adders and natural gas price sensitivities into one single figure. It shows the combination of GHG adders and natural gas price where the C/PNW-NC Line has a benefit-to-cost ration greater than 1.

Figure 21
Natural Gas Price Sensitivity – Case B1

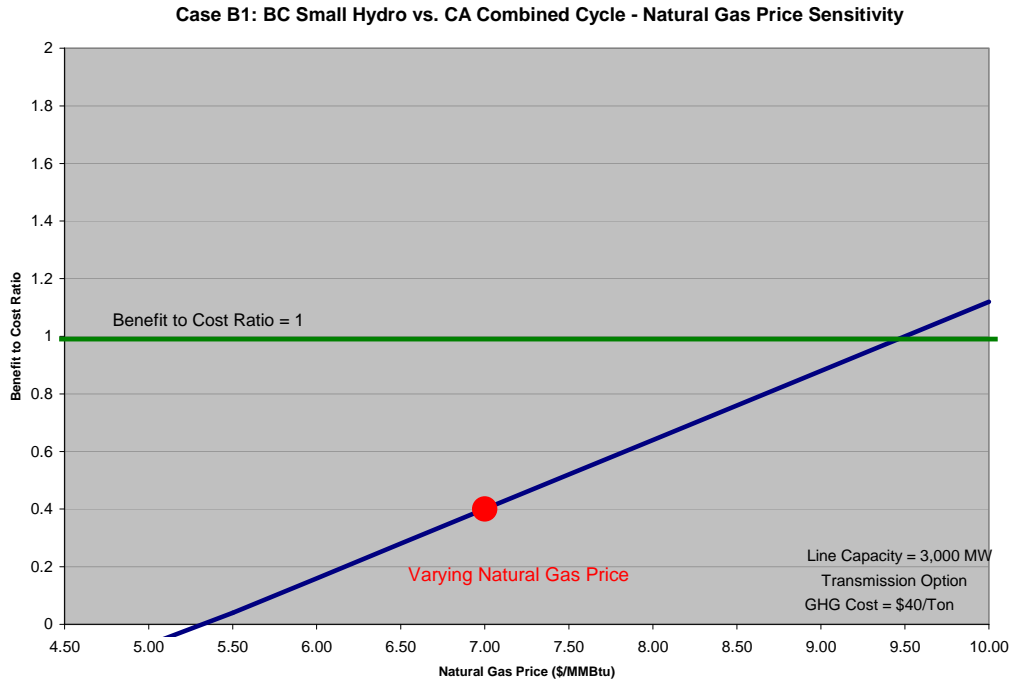


Figure 22
Natural Gas Price Sensitivity – Case C1

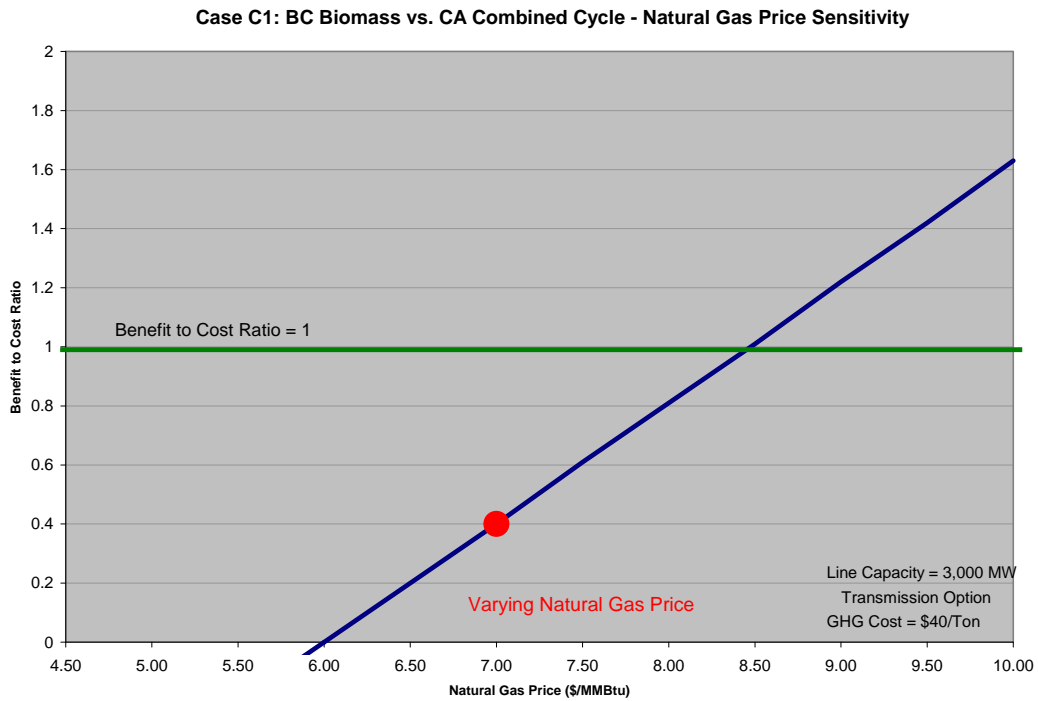


Figure 23
Greenhouse Gas Adder Sensitivity – Case B1

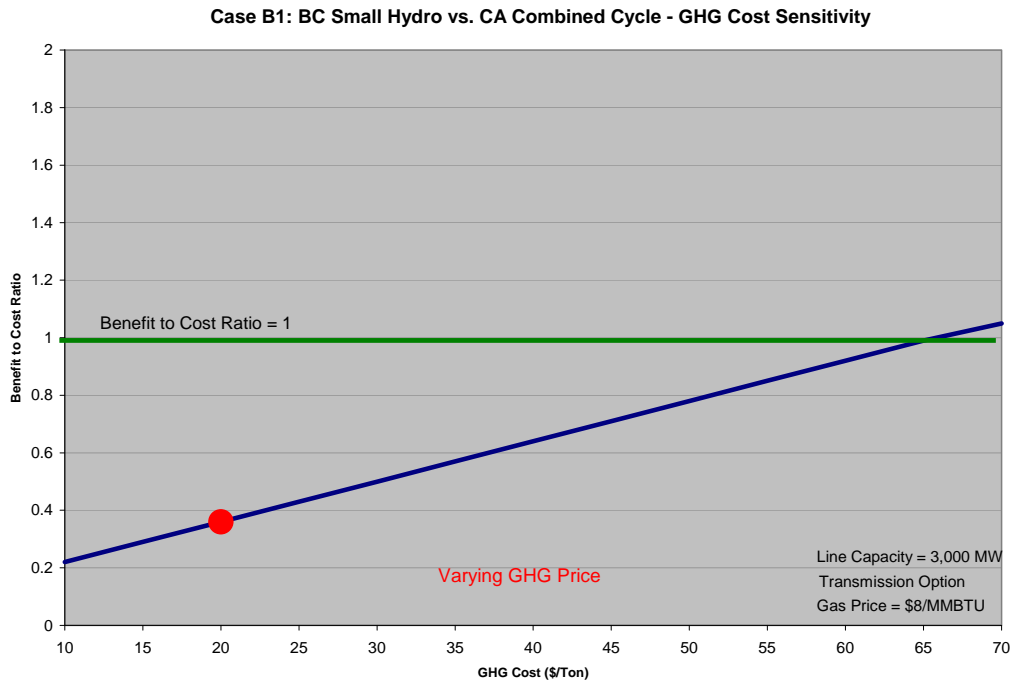


Figure 24
Greenhouse Gas Adder Sensitivity – Case C1

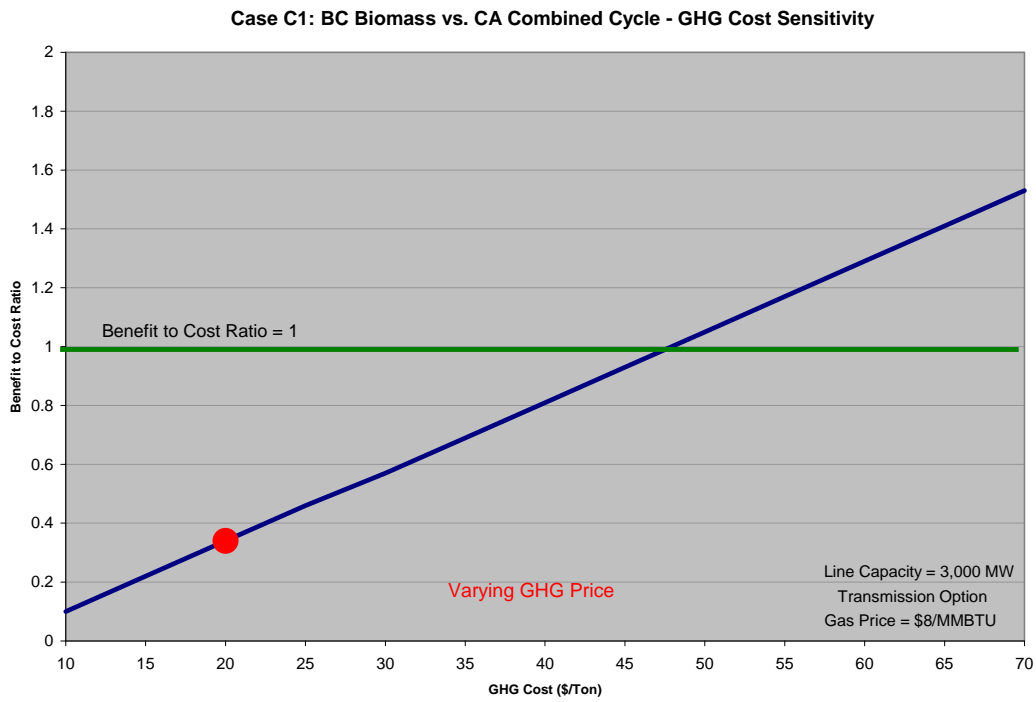
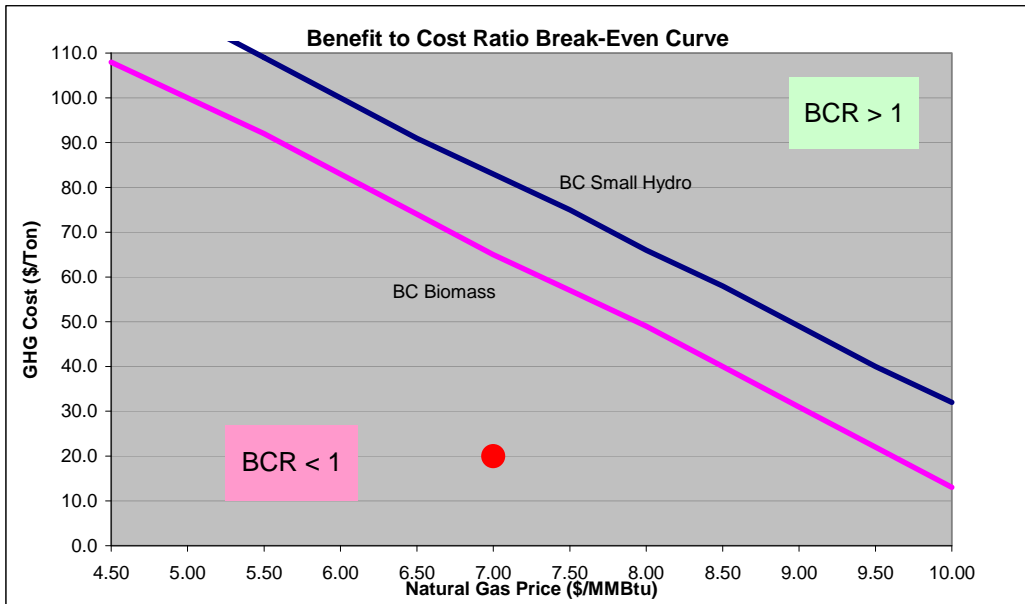


Figure 25
Natural Gas Price & Greenhouse Gas Adder Sensitivity – Cases B1 & C1



Renewable Resources Installed Cost and Capacity Factor

The reference data set has a reference set point value and a suggested range for the installed cost and capacity factor for new incremental biomass, wind and small hydro resources in British Columbia. Table 14 lists the benefits-to-cost ratio of the various cases and how they vary as the installed cost and capacity factor assumptions changed. As expected, benefit-to-cost ratio varies directly with capacity factor and inversely with installed cost of British Columbia renewable resources.

Table 14
BC Resource Installed Cost and Capacity Factor Sensitivity – Cases A & B

	BC Resource Installed Cost (\$/kW)	BC Resource Capacity Factor (%)	(1) CA CC	(2) CA Wind	(3) CA CSP	(4) CA RPS Mix
(A) 3600 MW BC Wind	1500	32	< 0	< 0	0.9	0.4
	1500	40	0.3	0.4	1.6	1.0
	1500	48	0.7	0.8	2.3	1.5
	2000	32	< 0	< 0	0.3	0.0
	2000	40	< 0	0.5	1.0	0.6
	2000	48	0.2	1.1	1.8	1.2
	2500	32	< 0	< 0	< 0	< 0
	2500	40	< 0	0.7	0.4	0.3
2500	48	< 0	1.4	1.2	1.0	
(B) 3600 MW BC Small Hydro	1800	36	< 0	0.5	0.9	0.6
	1800	44	0.3	1.2	1.7	1.3
	1800	48	0.5	1.5	2.1	1.6
	2000	36	< 0	0.3	0.7	0.4
	2000	44	0.1	1.0	1.5	1.1
	2000	48	0.3	1.3	1.9	1.4
	2800	36	< 0	< 0	< 0	< 0
	2800	44	< 0	0.2	0.8	0.3
2800	48	< 0	0.5	1.1	0.7	

Similarly, benefit-to-cost ratio varies inversely with capacity factor and directly with installed cost of California renewable resources. Figures 26-29 illustrate this relationship for California concentrating solar power and wind resources.

Figure 26
California Concentrating Solar Power Capacity Factor Sensitivity – Case D3

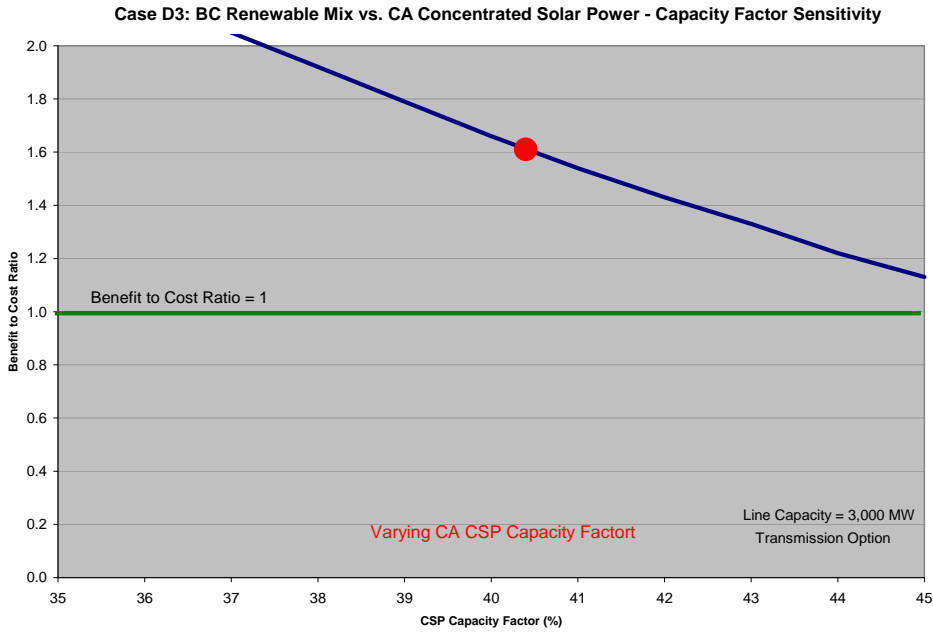


Figure 27
California Concentrating Solar Power Installed Cost Sensitivity – Case D3

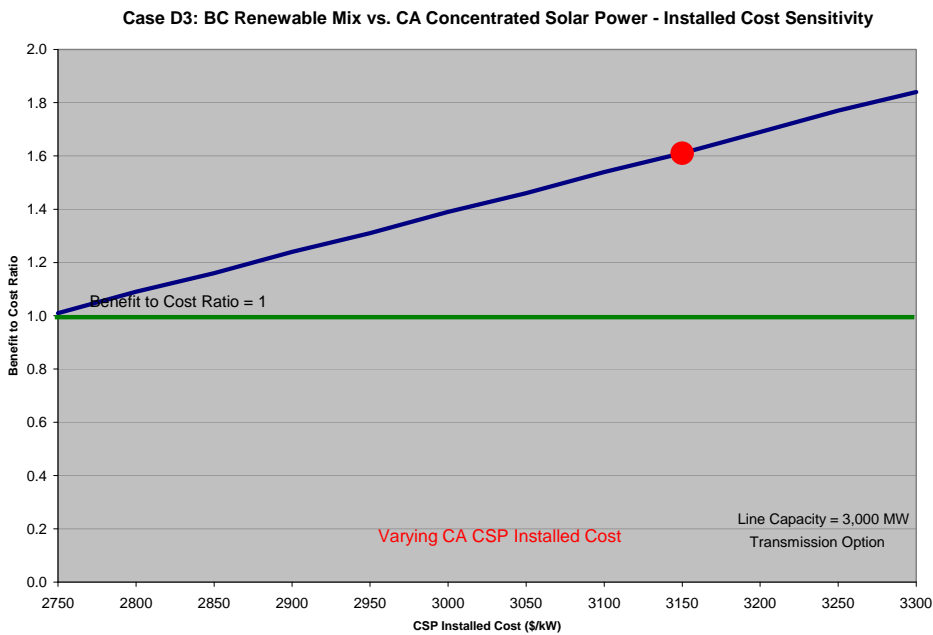


Figure 28
California Wind Capacity Factor Sensitivity – Case D2

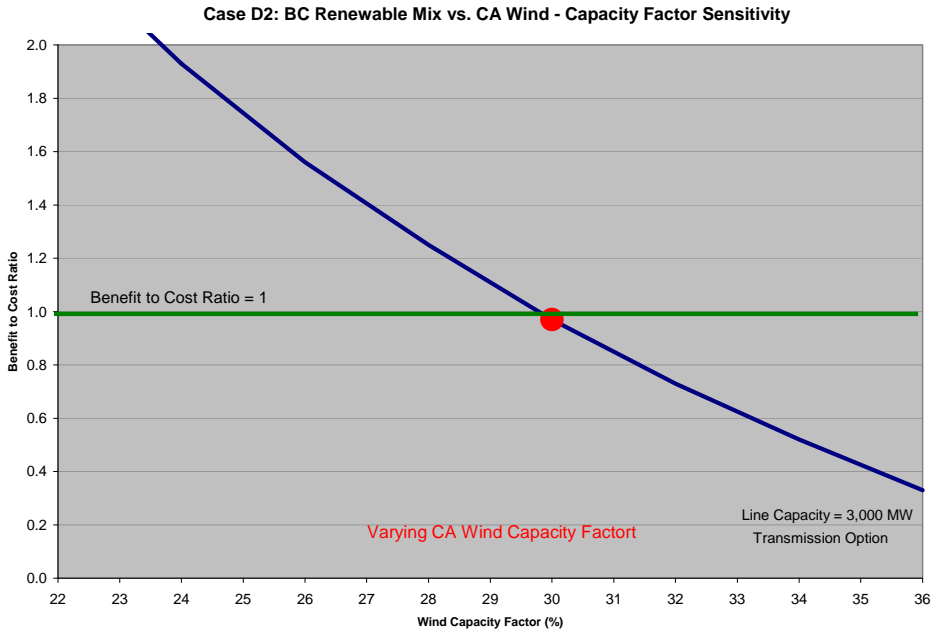
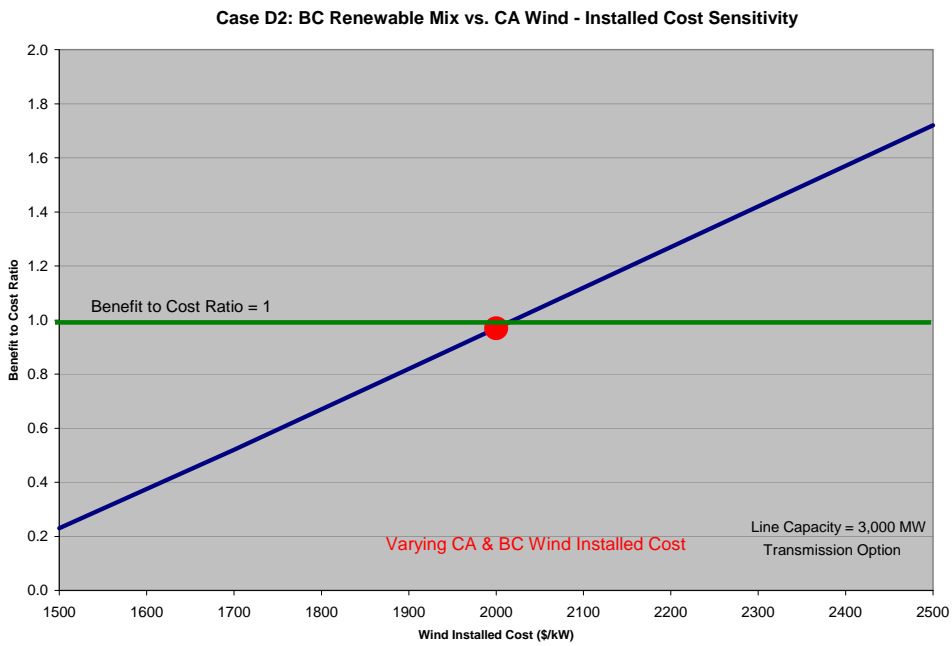


Figure 29
Wind Installed Cost Sensitivity – Case D2



C/PNW-NC Transmission Line Cost

The Economic Analysis Committee focused its efforts on analyzing a reference point “backbone” transmission configuration. The EAC used Transmission alternative 1 from the Technical Analysis Committee as the “backbone” configuration. This is a \$4.05 billion (based on one estimate), 3,000 MW AC line from British Columbia to northern California with intermediate connection points in Washington and Oregon. The annualized cost for this line is 400 million dollars (in 2006 US dollars).

Subsequent to the selection of Transmission Alternative 1 as the reference point, the EAC was informed that there are additional uncertainties with the estimated cost of this and other transmission alternatives developed by the Technical Analysis Committee. The treatment of local area transmission upgrade costs could significantly add to or reduce from the total cost of the transmission alternatives. Furthermore, it appears, based on further power flow analysis completed by the Technical Analysis Committee, that a hybrid transmission using alternate current (AC) and direct current (DC) configurations will provide superior power system performance as compared to a traditional AC or DC configuration. Moreover, a hybrid configuration could also result in a lower transmission project construction cost.

In light of the local area transmission upgrade costs and configuration uncertainty, the Economic Analysis Committee evaluated a range of transmission capital cost from \$2.5 billion to \$5.2 billion with \$4.05 billion as the reference point. The following table (Table 15) shows the impact of this capital cost range to the benefit-to-cost ratio of the various cases.

Furthermore, it appears that additional transmission planning analyses recently completed by the Technical Analysis Committee are indicating that a hybrid transmission configuration may provide better power system performance. Additional economic analysis must be undertaken once the transmission project’s plan of service and cost estimate are further defined.

Line Utilization

Line utilization is another key factor that influences the economic feasibility of the transmission project. The heavier the line is being loaded, the lower the per unit transmission cost to move a unit of energy. Figure 28 illustrates this relationship. The three curves in Figure 28 represent the per unit transmission cost for a transmission line that costs \$2.5 billion, \$4 billion, and \$5.2 billion, respectively. Using the middle curve (\$4 billion) as an example, if the line is loaded at 30%, the corresponding transmission per unit cost is about \$50/MWh. For the project to be cost effective, the price differential between source and sink must be more than \$50/MWh which is somewhat difficult to obtain. On the other hand, if the line utilization factor is at 90%, the transmission per unit cost would be reduced down to below \$20/MWh, which represents a lower barrier to overcome. Please note that these curves are for illustrative purposes since there are much uncertainty on the transmission line’s cost estimate and cost allocation arrangements.

Table 15
Transmission Line Cost Sensitivity

(A) Benefit-to-Cost Ratio for a Transmission Line Cost of \$4.05 Billion

	(1) CA CC	(2) CA Wind	(3) CA CSP	(4) CA RPS Mix
(A) 3600 MW BC Wind	0.0	0.5	1.0	0.6
(B) 3600 MW BC Hydro	0.1	1.0	1.5	1.1
(C) 3000 MW BC Biomass	0.0	1.4	2.3	1.6
(D) 3400 MW BC Mix	0.0	1.0	1.6	1.1

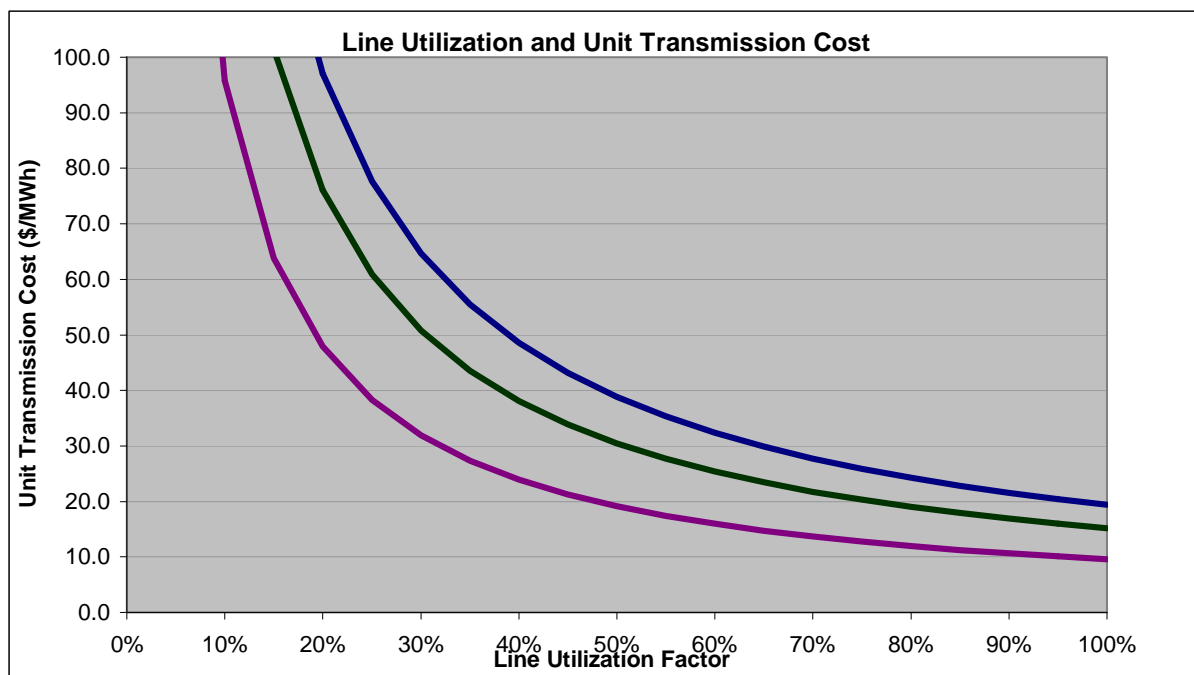
(B) Benefit-to-Cost Ratio for a Transmission Line Cost of \$5.2 Billion

	(1) CA CC	(2) CA Wind	(3) CA CSP	(4) CA RPS Mix
(A) 3600 MW BC Wind	0.0	0.4	0.8	0.5
(B) 3600 MW BC Hydro	0.1	0.8	1.2	0.9
(C) 3000 MW BC Biomass	0.0	1.1	1.8	1.2
(D) 3400 MW BC Mix	0.0	0.8	1.3	0.9

(C) Benefit-to-Cost Ratio for a Transmission Line Cost of \$2.5 Billion

	(1) CA CC	(2) CA Wind	(3) CA CSP	(4) CA RPS Mix
(A) 3600 MW BC Wind	0.0	0.9	1.6	1.0
(B) 3600 MW BC Hydro	0.2	1.6	2.5	1.8
(C) 3000 MW BC Biomass	0.0	2.3	3.7	2.6
(D) 3400 MW BC Mix	0.0	1.6	2.6	1.8

Figure 28
Relationship between Transmission Unit Cost and Line Utilization Factor



Opportunity for Seasonal Energy Exchange and Potential Grid Efficiency Improvements

Peak electric demand in British Columbia occurs during winter months while peak demand in California occurs during summer months. A new C/PNW-NC transmission line could create an opportunity for reliability firming and seasonal energy exchange. One way to account for this opportunity is to estimate a \$/kW capacity value that reflects the value of dependable winter capacity in British Columbia. A possible range for such a capacity value is \$40/kW-yr¹⁶ (based on California summer value) to \$120/kW-yr (based on the annual fixed costs of a new Combustion Turbine).¹⁷

Another benefit of a new C/PNW-NC transmission line is the grid efficiency improvement that it could bring. Such benefits, such as reserve sharing, congestion and losses reduction, and opportunities for economy energy, are typically estimated using production simulation models. These benefits are typically estimated later in the project planning and development stage once the project’s plan of service has been firmed up.

For this screening benefit-to-cost ratio analysis, the Economic Analysis Committee did not perform any quantitative analysis on these potential benefits.

¹⁶ \$40/kW-yr is based on the cost of backstop capacity included as part of the CAISO’s Reliability Capacity Services Tariff (RCST)

¹⁷ \$120/kW-yr is based on the annual fixed costs associated with a Combustion Turbine with an installed cost of \$750/kW in 2006\$ described in the Natural Gas section of this document.

7. *Findings*

This report was prepared as part of the WECC regional planning process for the C/PNW-NC Transmission Project solely for the purpose of an initial economic screening. Inputs into and results of this report are preliminary in nature, highly sensitive to assumptions selected, and are provided to be indicative to provide insight. Input assumptions were selected to test what-if situations and they do not necessarily represent the view of the Economic Analysis Committee. Screening level benefit-cost analysis performed by the Economic Analysis Committee leads to the following findings regarding the C/PNW-NC Line:

- 1) The benefits of a C/PNW-NC Line appear greater than the costs under a variety of conditions. There are also scenarios with less than 1.0 benefit-to-cost ratio.
- 2) Economics of the C/PNW-NC Line are sensitive to the cost and utilization of the transmission line; and the capital costs, performance, availability and accessibility of renewable resources in the British Columbia, the Pacific Northwest and California.
- 3) Grid efficiency improvements and the opportunity for regional seasonal power exchange¹⁸ may provide additional economic justifications. In-depth quantification of such benefits is beyond the scope of this screening analysis, but should be completed as the planning of C/PNW-NC Line proceeds forward.

¹⁸ A C/PNW-NC line can create an opportunity for reliability firming and seasonal energy exchange to serve winter peak demand in British Columbia.

Appendix 1

Members of the Canada to Northern California Electric Transmission Line WECC Regional Planning Project Economic Analysis Committee

- Avista Corporation: Dave DeFelice
- British Columbia Transmission Corporation: Rohan Soulsby
- Flynn RCI: Pushkar Wagle
- Northern Arizona University: Dr. Susan Williams
- Northern Lights: Bill Hosie
- PacifiCorp: Kurt Granat, Jamie Austin
- PG&E: Curt Hatton, Robert Jenkins, Tom Miller, Todd Strauss, Manho Yeung
- Sierra Pacific: Jim McMorran
- TANC: Patrick Mealoy
- Tollhouse Energy: Thom Fischer
- Trans-Elect: Jerry Vaninetti
- Powerex: Gordon Dobson-Mack