An Alaska-British Columbia Transmission Intertie

Review of Previous Studies and Economic Evaluation in Light of Current Conditions

Prepared for:

The Alaska Energy Authority

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ACEP
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Executive Summary

The Alaska Energy Authority (AEA) contracted the Alaska Center for Energy and Power (ACEP) at the University of Alaska Fairbanks to review, evaluate, and assess in light of current conditions results of studies that consider the economic feasibility of constructing an electrical transmission intertie to connect the isolated Southeast Alaska grid to the interconnected power network in British Columbia, Canada. In particular, ACEP was tasked with reviewing and assessing two studies: the *Southeast Alaska Integrated Resource Plan*, completed by Black & Veatch (B&V) in July 2012, and the *AK-BC Intertie Feasibility Study*, completed by Hatch Acres Corporation (Hatch) in September 2007. Because both of these studies draw a considerable amount of information from it, ACEP also reviewed the *Southeast Alaska Energy Export Study*, completed by D. Hittle & Associates, Inc. (DHA) in May 2006. To some degree the studies build upon each other. For example, cost estimates developed for a project subcomponent in an earlier study are often updated for use in a later study.

The economic case for building an AK-BC intertie requires sufficient price disparity between the Southeast Alaska electricity market and electricity markets in British Columbia, the Pacific Coast, or elsewhere. That is, economic justification for new Intertie[1] construction requires that the cost of transmitting, or wheeling, power over the Intertie can be paid for with savings associated with generating electricity more cheaply in one region than in another. More concretely, an Intertie can be economically justified if it can (1) facilitate the export of excess hydropower from Southeast Alaska to Outside markets, or (2) import less expensive power generated within or transmitted through British Columbia to Southeast Alaska.

The economic case for an AK-BC Intertie is thus critically affected by three basic cost elements:

- Per-unit electricity and power prices in Outside markets
- Per-unit electricity and power prices in Southeast Alaska
- The cost of the intertie itself divided by the amount of power that would flow over the intertie, plus any additional wheeling costs associated with moving power from Outside markets to the AK-BC intertie connection.

The cost to produce electricity from the most favorable Southeast Alaska hydro projects, even under particularly favorable assumptions, appears to be $.10 - $.11/kWh. This is likely to exceed the netback value available from power exports. Accordingly, an Intertie does not appear to be supported by power exports. The result is valid for six modeled cases that use a wide range of input assumptions, as described below.

In Table ES-1, cases are arranged to successively address key sensitivities. Changes in assumptions from one case to the next are highlighted in orange. Case 1 replicates Black and Veatch's work, with a correction to Black and Veatch's calculation of the value of electricity lost through resistant heat in transmission (line loss). Cases 2-6 build on Case 1 but model lower Intertie tariffs that result from higher assumed throughput; this increases the value of exports compared to Case 1. Cases 3-6 explore alternative export markets for Southeast Alaska power. They contain data on market prices, tariffs for existing transmission, and line losses to the California, Pacific Northwest, and Alberta electricity markets. They address export economics given current conditions. Cases 4-6 assume that the Intertie's capital costs are publicly funded. They reduce AK-BC transmission costs, and directionally (if insufficiently) improve the economic viability of Southeast Alaska hydropower economics.

[1] For the remainder of this report "Intertie" is used to refer to a transmission line linking Southeast Alaska with British Columbia; "intertie" is used to refer to transmission lines that connect currently isolated microgrids within Alaska.

Table ES-1: Summary of Hydropower Export Economics: Netbacks appear inadequate to encourage new construction

Case 1: Black and Veatch, low export		*Case 3: Update, CA Market*		*Case 5: Update, PNW Market*	
California 'referent' Sales price	0.104	California 'referent' Sales price	0.090	PNW Market Price (Avista IRP)	0.080
BPA - southern intertie	0.004	BPA - southern intertie	0.002	BPA - southern intertie	0.000
BPA - main system	0.004	BPA - main system	0.002	BPA - main system	0.002
BC Hydro (100% load factor	0.005	BC Hydro (100% load factor), discounted	0.003	BC Hydro (100% load factor), discounted	0.003
AK - portion of AK-BC Intertie, 7.4 MW of power	0.058	AK - portion of AK-BC Intertie, 37.1 MW of power	0.012	AK - portion of AK-BC Intertie, 100% public funding, 37.1MW of power	0.002
Transmission subtotal	0.071	Transmission subtotal	0.019	Transmission subtotal	0.007
Line loss cost	0.009	Line loss cost	0.002	Line loss cost	0.001
Netback value	**0.024**	**Netback value**	**0.069**	**Netback value**	**0.072**
Case 2: Black and Veatch, high export		*Case 4: Update, CA, Intertie Subsidy*		*Case 6: Update, Alberta Market*	
California 'referent'	0.104	California 'referent' Sales price	0.090	Alberta Market Price	0.070
BPA - southern intertie	0.004	BPA - southern intertie	0.002	Alberta Transmission	0.034
BPA - main system	0.004	BPA - main system	0.002	BPA - main system	0.000
BC Hydro (100% load factor	0.005	BC Hydro (100% load factor), discounted	0.003	BC Hydro (100% load factor), discounted	0.003
AK - portion of AK-BC Intertie, 37.1 MW of power	0.012	AK - portion of AK-BC Intertie, 100% public funding, 37.1MW of power	0.002	AK - portion of AK-BC Intertie, public funding of entire intertie, 37.1MW of	0.002
Transmission subtotal	0.024	Transmission subtotal	0.009	Transmission subtotal	0.039
Line loss cost	0.003	Line loss cost	0.001	Line loss cost	0.005
Netback value	**0.077**	**Netback value**	**0.080**	**Netback value**	**0.026**

For all three potential export markets, at both sets of Intertie throughput assumptions, and regardless of whether the Intertie is publicly funded, the netback value of Southeast Alaska hydropower exports is inadequate to support the cost of new project construction. That is, the netback value of power exports is less than the cost of electricity from new hydropower projects (roughly \$.10-\$.11/kWh). Accordingly, power exports do not provide economic justification for Intertie construction.

The conclusion is reinforced by the fact that a series of potentially substantial costs will be incurred but have not been subtracted from modeled netback values. These costs include building the Canadian portion of the AK-BC intertie and necessary transmission infrastructure from new hydro projects to the Intertie; reserving transmission capacity that is unlikely to always be fully used (which raises effective transmission rates); and making other required Southeast Alaska Power Agency (SEAPA) system improvements.

Absent substantial subsidy, the cost of power imports also appears too high to justify Intertie construction from an economic perspective. As with the case for exporting power, multiple power import scenarios are considered. In general, the import cases do not compare favorably to building new hydropower projects in Southeast Alaska. Table ES-2 summarizes power import scenarios. (As with Table ES-1, changes in assumptions from one case to the next are highlighted in orange.)

Case 1 replicates Black and Veatch's work, again with correction to Black and Veatch's calculation of the cost of line loss. Cases 2-5 update Black and Veatch's work to reflect current market prices and transmission tariffs. Power imports from both the Pacific Northwest (Cases 1, 2, and 3) and Alberta (Cases 4 and 5) markets are considered. The effect on Intertie import economics of private (Cases 2 and 4) and public (Cases 3 and 5) funding is also assessed. If the Intertie were fully grant funded, at a cost of perhaps \$80 million to the state, then it appears that the Intertie might support the economic importation of power from the Pacific Northwest market. (Gains would be smaller than represented in Table 8, given that regional transmission upgrades have not been included in the import economic assessment, nor have the costs of reserving but not fully using transmission capacity within BC.) However, if the goal is to provide cheap power to Southeast Alaska, fully subsidizing local hydro projects might be a better way to provide similar amounts of power at significantly less expense (see Tables 4 and 5, below).

Table ES-2: Summary of Hydropower Import Economics: Import prices appear to exceed local value

Case 1: Black and Veatch	
PNW Market Price	0.070
BPA - main system	0.004
BC Hydro (100% load factor)	0.005
AK - portion of AK-BC Intertie, 7.4 MW of power	0.058
Transmission subtotal	0.067
Line loss cost	0.008
SE AK Import price	**0.146**

Case 2: Update, PNW Market	
PNW Market Price	0.08
BPA - main system	0.002
BC Hydro (100% load factor), discounted	0.003
AK - portion of AK-BC Intertie, 7.4 MW of power	0.058
Transmission subtotal	0.063
Line loss cost	0.008
SE AK Import price	**0.151**

Case 3: Update, PNW, Intertie Subsidy	
PNW Market Price	0.080
BPA - main system	0.002
BC Hydro (100% load factor), discounted	0.003
AK - portion of AK-BC Intertie, 100% public funding, 7.4MW of power	0.002
Transmission subtotal	0.007
Line loss cost	0.001
SE AK Import price	**0.088**

Case 4: Update, Alberta Market	
Alberta Market Price	0.070
Alberta Transmission	0.034
BPA - main system	0.000
BC Hydro (100% load factor), discounted	0.003
AK - portion of AK-BC Intertie, 7.4 MW of power	0.058
Transmission subtotal	0.095
Line loss cost	0.012
SE AK Import price	**0.177**

Case 5: Update, Alberta, Intertie Subsidy	
Alberta Market Price	0.070
Alberta Transmission	0.034
BPA - main system	0.000
BC Hydro (100% load factor), discounted	0.003
AK - portion of AK-BC Intertie, 100% public funding, 7.4MW of power	0.002
Transmission subtotal	0.039
Line loss cost	0.005
SE AK Import price	**0.114**

Despite these rather negative conclusions it may turn out that the state is willing to subsidize the AK-BC Intertie. Economic viability may be a secondary consideration if transmission infrastructure is deemed necessary for regional development, or serves other broad policy goals. The risks of underwriting infrastructure that might sit substantially idle, used substantially for the occasional spot transaction, may be deemed worthwhile. Nevertheless, because state funds are limited, it is reasonable to assess whether a subsidized Intertie better serves regional aspirations better than subsidies for other local projects.

Abbreviations

ACSR	Aluminum-conductor-steel-reinforced
AK-BC	Alaska to British Columbia
B&V	Black and Veatch
BC	British Columbia
BCTC	British Columbia Transmission Corporation
BPA	Bonneville Power Administration
DHA	D. Hittle & Associates, Inc.
GWH	Gigawatt-hour
IRP	Integrated resources plan
kWh	Kilowatt-hour
MW	Megawatt
MWH	Megawatt-hour
PNW	Pacific Northwest (generally alluding to the Washington-Oregon region)
PWK	Petersburg-Wrangell-Ketchikan
ROW	Right-of-way
SE AK	Southeast Alaska
SEAPA	Southeast Alaska Power Agency

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1.0 Introduction and Background

The Alaska Energy Authority (AEA) contracted the Alaska Center for Energy and Power (ACEP) at the University of Alaska Fairbanks to review, evaluate, and assess in light of current conditions the results of studies that consider the economic feasibility of constructing an electrical transmission Intertie to connect Southeast Alaska (SE AK) to British Columbia, Canada (BC). In particular, ACEP was tasked with reviewing and assessing two studies:

- The *Southeast Alaska Integrated Resource Plan*, completed by Black & Veatch (B&V) in July 2012, and
- The *AK-BC Intertie Feasibility Study*, completed by Hatch Acres Corporation (Hatch) in September 2007

Because both of these studies considerably draw from it, we also reviewed:

- The *Southeast Alaska Energy Export Study*, completed by D. Hittle & Associates, Inc. (DHA) in May 2006.

To some degree the studies build upon each other. Cost estimates developed for a project subcomponent in an earlier study are often updated for use in a later study.

However, to a considerable extent, the studies do not constitute a unified body of work. They address different research questions, respond to different priorities, and have different geographic scopes. Accordingly, they make markedly different assumptions with regard to State investment, project configuration, and business risk, and provide at times different levels of descriptive detail regarding key assumptions that drive conclusions.

This complicates the assigned task. Taken literally, a critical review in light of current conditions would entail substantially separate reviews – one for each study. We have therefore adopted a somewhat different tack: to assess the economic case for building an Alaska-British Columbia (AK-BC) Intertie given previous work and in light of current conditions.

At minimum, the economic case for building an AK-BC Intertie requires sufficient electricity price disequilibrium between the SE AK market and electricity markets in BC, the Pacific Coast, or elsewhere in the Western Electricity Coordinating Council region. That is, economic grounds for new Intertie construction require that the cost of wheeling power over the Intertie can be paid for with savings associated with generating electricity more cheaply in one region than in another. Stated in this way an intertie would need to be economically supported by at least one of the following three potential cases:

- To facilitate export of excess hydropower – whether existing or new-build – from SE AK to “outside” (Outside) markets
- To permit import into SE AK of less expensive power generated within or transmitted through BC
- To permit both import and export of power from SE AK in a way that optimizes existing and future assets.

This report addresses the first and second cases. The last case was not quantitatively modeled by any of the reviewed studies, and rigorously addressing it would involve considerable original modeling – a task outside the scope of the current engagement. We note that the case for joint economic import and export is not only more complex to assess – implicit is that potential price disequilibria can move from one to the other market on a relatively short time scale – but also engenders greater business risk. It is unclear how long term contracts could be used to materially reduce business risk of paying for the Intertie. Without such contracts the risk has to be borne by the Intertie sponsor. Whether doing so is prudent is a judgment call that would reflect regional and state development priorities. Finally, as a practical matter, if neither the export or import cases generate positive returns then it seems unlikely that the joint import/export case will do so.

1.1 Structure of the Report

First, a fairly lengthy summary that compares the aforementioned reports is provided. Given multiple but only partially overlapping studies, there is considerable opportunity for those with different views to site different aspects of different studies. The hope is to provide sufficient context to each of the studies, and study results, to facilitate clarity and forestall argument founded on misunderstanding rather than principle. Accordingly, we begin with a review of the major (and somewhat disparate) questions that each report addresses.

The comparative summary is then organized around major project economic elements. These include: project study area; regional transmission and hydropower generation options; hydropower costs and uncertainties; Intertie routing, costs, and transmission rates; and wheeling costs to and associated prices in outside electricity markets. Reviewing conclusions around each element facilitates consideration of the degree to which the economic viability of the Intertie may have changed. The section concludes with discussion of key report findings.

Second, we address the organizing question behind this report –the economic case for an AK-BC Intertie – in light of current conditions. Our question critically implicates three cost elements:

- Per-unit electricity and power prices in the outside-Alaska market
- Per-unit electricity and power prices in SE AK
- The cost of the Intertie itself, divided by the amount of power that would flow over the Intertie, plus any additional wheeling costs associated with moving power from the Outside market to the AK-BC Intertie connection.

None of these cost elements are static.

Prices in both markets are determined by changing dynamics that affect the cost of supply and level of demand. Outside electricity markets are comparatively large. This provides inherent buffering in underlying market conditions. Significant price effects will occur only given broad changes in key drivers, such as sustained shifts in natural gas prices, policy requirements regarding renewable energy supply, or macroeconomic booms and busts.

Conversely prices in the smaller SE AK markets should, as a theoretical matter, be more volatile. Regulatory hurdles can lead to substantial increases in proposed project costs; refinement of project scope seems inevitably to result in substantial cost escalation as the complications of construction logistics in remote regions are better appreciated;[2] a single new large industrial project (e.g., a large mine) might materially change regional demand relative to existing supply options.

Costs of the necessary Intertie infrastructure also evolve. As transmission infrastructure extensions are built in BC, the cost of moving power from Alaska into BC becomes more feasible. And, of course, general cost escalation marches on.

[2] The stories of project cost escalation in Alaska are legion, from the experience on the Trans-Alaska Pipeline System to projections concerning proposed hydropower project costs in Southeast Alaska.

The report concludes with what is, essentially, an endorsement of B&V's major findings. Indeed, if anything, market trends appear generally to further undercut the economic rationale for AK-BC Intertie construction. Summary tables of a range of "export" and "import" cases, with sensitivities for Intertie funding, outside market values, and the like, are provided. They indicate that the basic economic case for an intertie does not appear favorable.

2.0 Review of Earlier Studies

2.1 Report Research Questions

DHA's main research question concerns the revenue that might be earned at the busbar of new and existing hydro projects in SE AK if an Intertie were constructed using grant funds. They describe their charge as evaluating "… the feasibility of the Bradfield Intertie based on the revenue that would be produced from power sales over the line as compared to the costs of its operation and maintenance." Because DHA define net benefits "…as the revenues estimated to be received from the sale of power to outside markets less the costs of transmitting power to these markets", they are not concerned with the capital cost of SE AK hydropower projects nor with the capital costs of the Intertie itself. By implication DHA's research lens provides an assessment of the breakeven cost of energy for potential hydro projects under best-case conditions. As corollary, if one assumes those best-case conditions could be satisfied, the DHA report helps answer whether export revenue would be sufficient to recover costs.

Hatch evaluates an intertie within a broader system that includes other interties linking subregions within SE AK "…for use by decision-makers in reviewing and evaluating proposals for funding and related state action on proposed transmission segments and related issues." Hatch reviews the SE energy market, the export electricity market, potential transmission projects, potential hydro projects, the regulatory environment, and business structures for a SE intertie to inform the construction and inputs of an economic optimization model. Hatch deploys this computer model to determine least-cost plans to supply electricity, both with and without a SE intertie that would enable exports. In essence, Hatch develops integrated resource plans that involve intertying various Southeast communities, where the main resources considered were diesel thermal, SE hydropower, and potential revenue from export of hydropower on a grant-funded Intertie. The Hatch planning focus therefore involves assessment of comparative costs of new and existing generation resources. The Intertie's role is conceived primarily as creating a market outlet for SE hydropower project power that might exceed local demand,[3] thereby facilitating hydropower infrastructure development that could help foster economic growth.

B&V consider Intertie feasibility within the context of a more comprehensive Southeast Alaska Integrated Resource Plan. All potential supply and demand side management options were notionally "on the table". For B&V, therefore, the Intertie is addressed essentially as a potential additional resource. Stated differently, and unlike the DHA and Hatch reports, B&V assess an Intertie not from the perspective of whether it might offer a business case for export of new-build SE hydropower, but from whether it might offer a more cost effective solution to Southeast power needs. B&V conducted a "high level screening" of an AK-BC intertie under two scenarios, export *and* import, to preliminarily evaluate economic feasibility of the intertie before inclusion in IRP modeling efforts. For the import case the goal is to assess whether an Intertie might facilitate lower cost power imports than might otherwise be achieved from local generation

[3] The Hatch report never assesses a business case of the Intertie in which it functions primarily as a mechanism for power imports, or in which imported power potentially displaces SE generation options.

options. For the export case the goal is to assess whether new-build hydropower projects in SE Alaska could profitably market electricity in outside markets. B&V's economic screening develops prices for export and import power markets, estimates transmission, capital, and O&M costs, and compares the resulting cumulative price of power to potential generation costs in SE Alaska.

None of the studies explicitly modeled the regional economic costs and benefits, in terms of direct, indirect and induced employment impacts of construction and operation, of having an Intertie in place. Further, while qualitative acknowledgement was made, no quantitative modeling was done of associated:

- Increased flexibility of power system operations by virtue of being connected to a larger system
- Opportunity for further optimization of system resources
- Reductions in the amount of spinning reserve
- Reduced greenhouse gas emissions.

The different research questions cause differences in the project elements and that each report considers.

2.2 Report Study Areas: Regional Transmission and Generation Options

Economics of an Intertie will be affected by its use. Potential generation options within SE Alaska that might conceivably make use of an Intertie differ substantially across the three studies. Accordingly, we briefly compare the studies' geographic and energy project scope.

DHA considers several different configurations of a SE energy market with which an Intertie might connect, with the goal of assessing the volume of potential power that could be exported. As more sub-regions are interconnected more hydropower projects might be developed, with significant surplus power available for export. (Figure 1) We report on four of these configurations, as DHA's Base Case has been superseded by completion of the Swan – Tyee Intertie:

- Case 1: DHA projected that completing the Swan – Tyee Intertie, which connected the electric systems of Ketchikan with Petersburg and Wrangell (the PWK area), would leave perhaps 53,000 MWH/year of surplus power for export.[4]
- Case 2: Consists of Case 1, plus construction of the Cascade Creek hydroelectric project.[5] This could result in surplus of about 260,000 MWH annually for export.
- Case 3: Consists of Case 2, plus all potential hydroelectric projects currently identified in the PWK area.[6] This results in a surplus of about 676,000 MWH annually available for export.
- Case 4: Consists of Case 3, with the addition of transmission interconnections between PWK and Kake, the Sitka region, and Angoon, as well as assumed construction of yet more hydroelectric generating facilities that could yield potentially 800,000 MWH of exportable energy.[7]

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[4] No new hydroelectric facilities were projected to be constructed in the PWK interconnected system.

[5] Cascade Creek (45 MW, delivering 203,000 MWH annually) is one component of the proposed Thomas Bay Project.

[6] This case assumes the construction of a transmission line between Metlakatla and Ketchikan. Potential hydroelectric facilities: Lake Tyee Third Turbine (10 MW), Thomas Bay Project (Ruth Lake, Scenery Lake, 50 MW), Sunrise Lake (4 MW), Anita - Kunk Lake (8 MW), Virginia Lake (12 MW), Thoms Lake (7.3 MW), Whitman Lake (4.6 MW), Connell Lake (1.9 MW), Mahoney Lake (9.6 MW), Triangle Lake (3.9 MW). DHA assumes a uniform 60% capacity factor to develop annual average electricity generation estimates. DHA assumes that all projects come online in 2010 (except for the Thomas Bay project, which comes online in 2012), acknowledging that project start dates might be significantly later.

[7] Additional hydroelectric facilities are assumed to be built in the Sitka area and in Angoon: Takatz Lake (20 MW), Katlian River (7.0MW), Sterling Bolima (1.0 MW). Again, DHA assumes a Suniform 60% capacity factor.

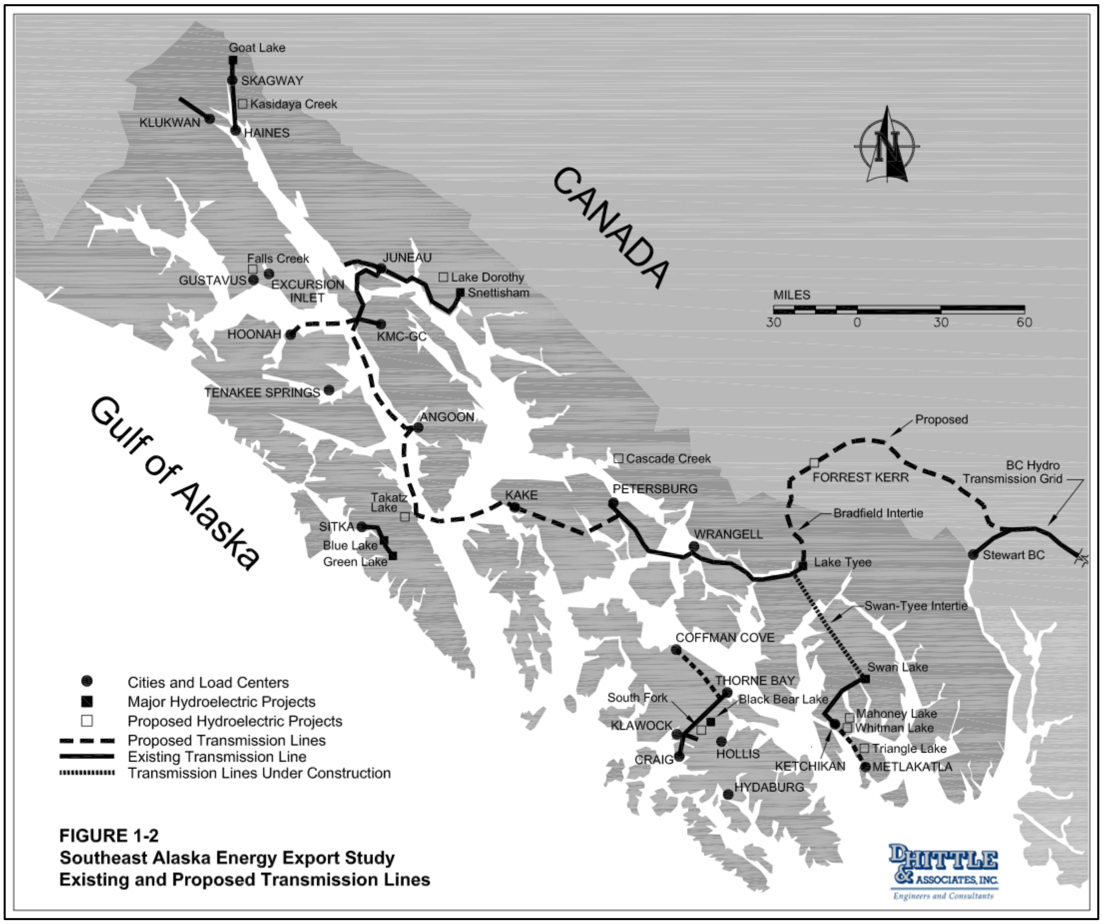

Figure 1: DHA study area, potential Southeast grid, and associated hydropower projects

The Hatch report assumes SE AK interconnections consistent with DHA's "Case 4". Hatch's set of potential new-build hydropower projects differs somewhat from DHA's, however. The Carlanna Lake and Reynolds Creek projects near Ketchikan were added, and the Katlian (north of Sitka) and Sterling Bolima (Angoon-based) projects were dropped. Finally, while Hatch does address the Takatz Lake project – which would entail a subsea transmission line to Kake – the cost of this line was separately guessed at about $160 million. This substantial interconnection cost reduces the likelihood of that project contributing to power export.

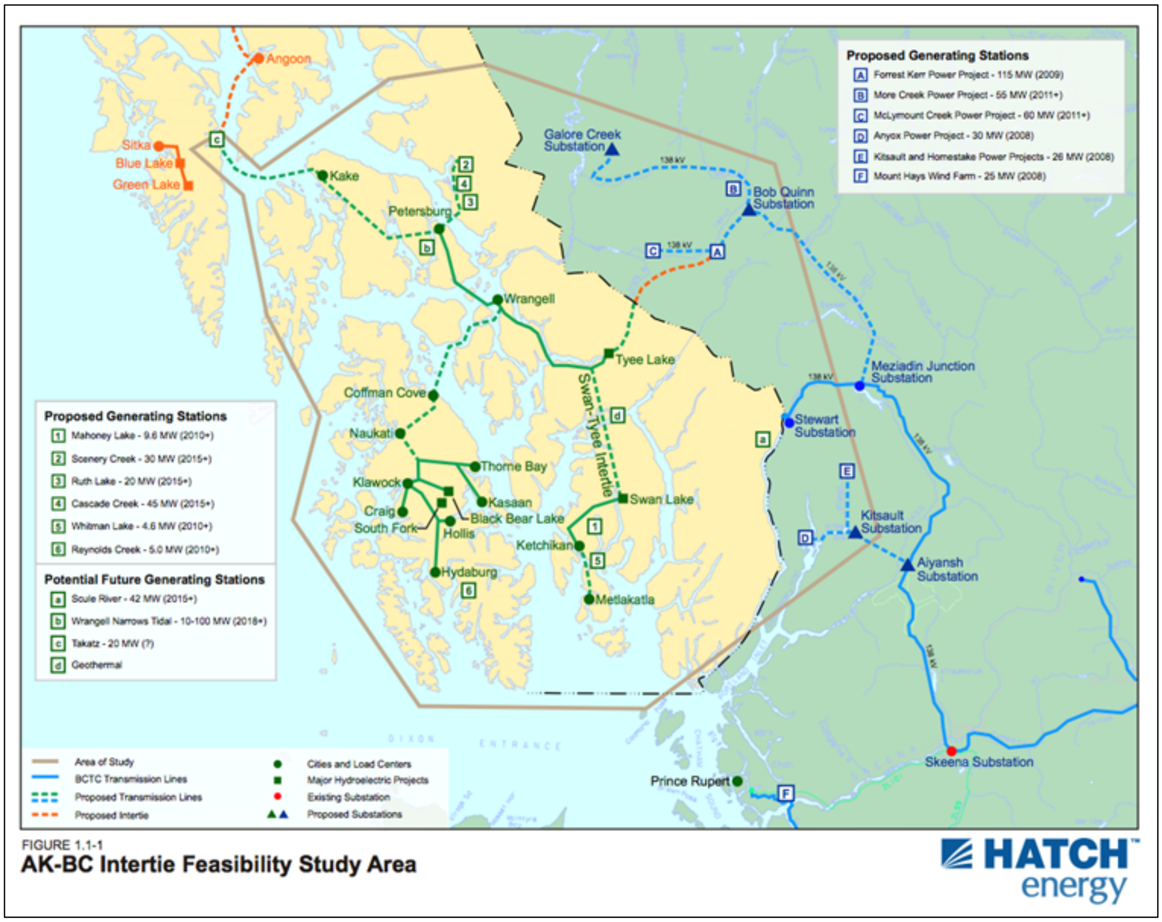

Figure 2: Hatch study area, potential Southeast grid, and associated hydropower projects

The B&V report, as an IRP for the entire Southeast region, considers energy solutions for communities from Yakutat to Metlakatla. Potential new transmission interties connecting Juneau and even Haines to a comprehensive Southeast grid were considered (Figure 3). In all, B&V collates nearly 300 potential hydro projects in the region that have been identified over the years (see Appendix C, Black and Veatch, 2012).

B&V endorses an AEA-suggested series of criteria that should be satisfied for a given hydro project to be considered worthy of further consideration as a potential supply-side option. These include: realistic commercial operation date; cost estimate at the project feasibility level; adequately measured water flows; risk assessment regarding regulatory challenges; a well-developed business plan; fatal flaw analysis; estimated electricity rates (Black and Veatch; p. 10-4). The vast majority of the collated hydro projects are described at having, at most, a cursory development concept.

The screening process results in a list of 42 projects deemed potentially feasible at the time of the report. (B&V, Table 10-2). Five of these are deemed to be "committed", or already significantly launched, and so are included in baseline supply resource modeling. Their power is seen as needed to meet regional demand. (Of these five, Reynolds Creek and Whitman Lake had previously been considered by Hatch.) Another 13 are characterized as being developable primarily to serve mine loads; interconnection to the SE AK utility grid is not expected to occur if the projects are developed. Accordingly, they would not generally be expected to help undergird regional intertie or AK-BC Intertie projects (B&V, p. 10-9). The remaining 24 projects substantially overlap with those addressed by Hatch, including an additional 6 due to the broader geographic study area considered. (Compare Figure 2 and Figure 3 with B&V, Table 10-4.)

Figure 3: B&V study area, potential SE AK grid, and associated hydropower projects

2.3 Report Hydropower Costs: Issues and Uncertainties

The cost of new-build SE AK hydropower is one of the key variables affecting economic viability of an Intertie. If costs are too high, then the economics of export are undermined. If costs are too low, then comparative economics of power import (as opposed to within-region generation) will fail.

None of the three studies developed their own bottom-up hydropower capital cost estimate. Both Hatch and B&V relied considerably on cost estimation work performed by others. Unfortunately, different entities have done cost estimation for different projects, at different times. Estimates for most projects have considerably aged. Some of were made in the 1970s, some in the 1990s, and some in the last decade. (Table 1) Given available data, and inherent limitations imposed by different and inconsistent methodologies, error bounds on the cost of different hydroelectric projects are wide. This raises issues as to current applicability, and inter-project comparability.

Table 1: Potential SE hydroprojects, the year and source of cost estimation, estimated capital costs, and costs of power. Modified from Hatch (2007; p. 179)

Project Name	Source and Vintage of Cost Estimate	Order of Magnitude Costs (2007$) Capital Cost ($1000)	Variable Cost ($1000)	Cost of Power ($/kW)
Mahoney Lake	FERC License, 1998	34,073	553	.085
Scenery Lake	Cascade Creek, LLC	84,442	1,695	.067
Delta Creek (Ruth Lake)	Cascade Creek, LLC	60,517	1,135	.086
Cascade Creek (Swan Lake)	Cascade Creek, LLC	144,959	2,535	.071
Whitman Lake	Hatch, 2006	9,738	273	.055
Connell Lake	RW Beck, 1996	7,779	110	.069
Carlanna Lake	RW Beck, 1996	3,735	60	.087
Triangle (Hassler) Lake	Hatch, 2007	15,613	211	.114
Takatz Lake	RW Beck, 1974	134,204	1,566	.117
Virginia Lake	RW Beck, 1977	127,575	687	.255
Thoms Lake	RW Beck, 1977	136,108	435	.481
Sunrise Lake	RW Beck, 1977	16,252	239	.117
Anita & Kunk Lakes	RW Beck, 1977	111,922	497	.345
Tyee Lake Extension	Harza, 1996	10,114	659	.073
Reynolds Creek	FERC License, 1998	19,166	295	.307

To help generate indicia of comparative costs of their 15 potential hydro projects, Hatch imposed common cost factors. These relate to financing, engineering, contingency, operation and maintenance, insurance, and the like. Hatch also used a single cost escalation index to bring cost estimates from different periods to 2007 dollars. Key assumptions are shown, below. (Table 2).

Table 2: Assumptions used to put project cost estimates on common footing. Modified from Hatch (2007; p. 178).

Item	Value
Total Capital Requirements	
Contingency	15% of Direct Construction Cost
Engineering & Owner Administration	15% of Direct Construction Cost
Interest During Construction	4% of Total Construction Cost
2007 USBR Cost Index	305
Fixed Costs	
Annual Interest on Bonds	6%
Bond Term	20 years
Financing Expense	2.5% of Total Capital Requirements
Working Capital Reserve	6 months of O&M costs
Variable Costs	
Operation and Maintenance	$32/kW
Administrative and General	$8/kW
FERC Compliance	$15,000/yr
Interim Replacements	$4/kW
Insurance	$12/kW

The resulting "order of magnitude" *total* capital cost estimates for the 15 projects are reproduced ("Capital Cost" column, Table 1).[8]

Given total project costs, Hatch uses two approaches to develop annual revenue requirements that recover costs over time. In the first instance, Hatch assumes investment recovery over 20-years (results in Table 1; in the second, Hatch posits levelized cost recovery over a 50-year FERC license period (Table 3).

Table 3: Potential SE hydropower costs of power, assuming 50-year cost recovery. Modified from Hatch (2007; p. 198).

Project Name	Levelized Unit Cost of Energy ($/kWh)
Whitman Lake	.0452
Mahoney Lake	.0540
Scenery Lake	.0548
Connell Lake	.0566
Cascade Creek (Swan Lake)	.0580
Carlanna Lake	.0707
Delta Creek (Ruth Lake)	.0704
Tyee Lake Extension	.0901
Triangle (Hassler) Lake	.0914

[8] While Hatch refers to their cost estimates as having "order of magnitude" accuracy this is almost certainly a misnomer. Strictly speaking, an "order of magnitude estimate" has accuracy within a factor of 10. We assume, instead, that Hatch intended to indicate the most loose "conceptual level" engineering estimate, which generally has accuracy within -50%/+100% (and, in practice, the upper end of the estimate is more likely than the lower).

In both cases it appears that Hatch assumes 100 percent debt financing, though in the first instance Hatch assumes private capital while in the second it recognizes the need for government investment. The joint assumptions of full debt financing and private ownership are not consistent. A private developer would not only want, but bond markets would require, it to invest substantial equity capital. The need for and significantly higher return required on private equity, as well as the potential tax burden that equity returns bear, would substantially raise the levelized power costs.[9] In general then, absent government-sponsorship, likely financing constraints suggest that Hatch's approach provides what are likely to be lower bound figures for the cost of new-build hydropower.

The per-unit cost of power is determined by dividing the (uncertain) annual revenue requirements, by the total expected amount of generated power (see Table 4). However, converting total annual project costs into per-unit costs of power raises additional complications and reveals further uncertainty. For all but two of the generation options, final approvals had not been received from relevant regulatory agencies at the time Hatch had completed their report. Accordingly, ultimate project capacity and energy estimates were unresolved: regulatory decisions could reduce the available electricity with potentially minimal reduction in total required capital expenditures. Hatch's indicative per unit energy costs ("cost of power" column, Tables 1 and 3) therefore probably again represent "best case" scenarios.

Table 4: Estimated energy and capacity figures. Modified from Hatch (2007; p. 176)

Project Name	Installed Capacity (MW)	Average Energy (GWh)	Firm Energy (GWh)
Mahoney Lake	9.6	39.6	34.3
Scenery Lake	30.0	128.7	102.8
Delta Creek (Ruth Lake)	20.0	70.7	57.6
Cascade Creek (Swan Lake)	45.0	202.3	159.1
Whitman Lake	4.6	19.6	17.0
Connell Lake	1.7	10.8	9.3
Carlanna Lake	0.8	4.2	3.6
Triangle (Hassler) Lake	3.5	13.1	11.4
Takatz Lake	20.0	106.9	97.1
Virginia Lake	12.0	43.8	37.9
Thoms Lake	7.5	24.2	20.9
Sunrise Lake	4.0	13.5	11.7
Anita & Kunk Lakes	8.6	28.1	24.3
Tyee Lake Extension	11.5	20.3	6.0
Reynolds Creek	5.0	6.1	5.5

Hatch modeled the two largest potential projects, Cascade Creek and Scenery Lake, as providing power for export in the relatively "near" term. The annual average power for export from these projects totaled 38 MWe with Cascade Creek coming online in 2015 and Scenery Lake in 2017. The cost of power for these

[9] Hatch tries to side-step this issue by asserting that their "economic analysis" – which ignores taxes and financing niceties – represents the true economic value of projects compared with a "financial analysis" (Hatch, p. 197). The problem is that financial realities must be considered if economic viability of the Intertie or of various hydropower projects is to be assessed.

projects was estimated at $.071/kWh (or $.058 on a 50-year levelized basis) and $.067/kWh (or $.0548 on a 50-year levelized basis), respectively.

Like Hatch, B&V notes "the wide variety in the quality and inclusiveness of information available to evaluate specific hydro projects" (B&V, p. 10-1). They conclude it impractical to do a proper "apples to apples" comparison of project costs and feasibility. Accordingly, so too is developing priority ranking for hydropower projects, especially against the need for new generation within subregions of SE AK. Against this backdrop, B&V takes three separate approaches to hydropower project costs, each of which was adapted to separate questions.

First, as earlier noted, B&V endorses an AEA-suggested series of criteria that should be satisfied for a given project to be considered worthy of further consideration. Project capacity and cost range figures are updated for each such projects based on regulatory developments. B&V updated the most recently available cost estimates to 2011 dollars using the non-nuclear electricity generation capital cost indices published by IHS CERA[10]. A notable B&V refinement, compared with Hatch, was development of capital cost ranges for each project to reflect B&V's assessment of project capital cost uncertainty.

Table 5: Capital expenditure estimate evolution and uncertainty (adapted from Black and Veatch, Table 10-4, via Hatch – see Table 1 – using IHS CERA indices)

Project Name	CapEx (1,000's of 2011$)		
	Hatch	B&V Lo	B&V High
Mahoney Lake	34,456	34,500	51,760
Scenery Lake	85,391	129,000	193,480
Delta Creek (Ruth Lake)	61,197	84,540	126,820
Cascade Creek (Swan Lake)	146,588	146,350	219,530
Whitman Lake	9,843	--	--
Connell Lake	7,866	5,400	10,800
Carlanna Lake	3,777	--	--
Triangle (Hassler) Lake	15,788	12,630	18,950
Takatz Lake	135,712	117,040	175,560
Virginia Lake	129,008	103,210	154,810
Thoms Lake	137,637	110,110	135,170
Sunrise Lake	16,435	16,640	24,960
Anita & Kunk Lakes	113,180	90,540	135,820
Tyee Lake Extension	10,228	13,200	30,800
Reynolds Creek	19,381	--	--

In half of the cases Hatch's capital costs point estimate is at or below the lower end of the B&V estimated range; in the remainder the Hatch estimate is within the range. A reasonable (if unsurprising) conclusion is that project costs appear generally to escalate as project definition improves.

[10] The IHS CERA cost indices can currently be found at http://www.ihs.com/info/cera/ihsindexes/index.aspx

However, B&V finds sufficient incommensurability in the cost figures to render the electricity rate information inadequate to make comparative investment decisions, or even to use in regional power modeling. Accordingly, for this purpose B&V developed a suite of 6 different "generic" hydro projects, with assumed capital and operating costs, costs of capital, annual and monthly energy output, and the like. For sub-regional modeling of power system needs B&V's optimization model "built" such projects as needed. Critically, however, B&V notes that the generic projects were not based on actual hydro project opportunities available in a given sub-region. The cost of this generic hydropower is accordingly not relevant to the question of whether an AK-BC Intertie might be economically justified.

B&V's third and final approach to assessing project hydropower costs is comparative. That is, in its "screening assessment" for whether an AK-BC Intertie was an economically viable option, B&V does not begin with an assessment of the cost and quantity of power available for export. Instead, they assess whether costs of economic generation of hydropower might be low enough – given outside market prices, and estimates of transmission costs – to enable profitable exports. Similarly, for the import case, B&V assessed whether outside market prices, plus estimated costs of transmission, were greater than favorable hydropower project costs. Were this the case, then an Intertie might be supported through power imports. If neither test can be passed then a comprehensive business case based on total costs of available power for export need not be developed.

For this comparative Intertie screening exercise B&V updates costs of two projects. The Whitman Lake project (the least expensive project from the Hatch list at $.055/kWh, or $.0452/kWh assuming 50-year levelized cost recovery) was, at the time of B&V's report, projected at around $.110/kWh; the Cascade Creek project appeared to have 50-year levelized energy cost of $.103/kWh, based on Exhibit D of its Draft FERC License Application.

2.4 Intertie Characterization: Routing, Specification, Costs and Rates

Any analysis of Intertie economic viability must address its construction cost. Construction cost is dependent upon routing and design. Remarkably, BC construction issues and costs receive only cursory treatment in the reviewed reports. DHA posits, for "discussion purposes", $17.4 million (2006$) for construction of the 35-mile line from the BC border to the Forrest Kerr project. (Figure 4) DHA suggests that this segment might be owned either by the eventual private developer of the Forrest Kerr project – in which case a separate transmission tariff would be required – or by BC Hydro. Hatch suggests a rough estimate of $36 million (2007$), based on simple mileage factors and construction conditions roughly similar to Alaska. B&V does not provide an estimate. The BC portion of Intertie costs was not included in economic assessment of SE AK power exports or imports. Similarly, none of the studies addressed costs of needed BC transmission infrastructure and system upgrades into their economic analyses. The remainder of this section is thus confined to the Alaska portion of Intertie costs.

For the Alaska portion of the Intertie, DHA proposes a 26.4-mile route that begins at the Lake Tyee hydroelectric project and would generally follow the (also proposed) Bradfield River Road to the AK-BC border. From the BC border, the Intertie would continue another 35 miles to the Forrest Kerr hydroelectric project. (Figure 4) DHA assumed that existing logging roads could provide construction site access for about 14 miles; elsewhere, helicopters would be needed for the majority of construction and O&M activities. After considering several different technical specifications DHA recommends a single wood pole (A-frame structures utilized to support long spans), single circuit 138-kV line (initially operated at 69-kV) with 556.5 ACSR conductors designed to export ~105 MW.

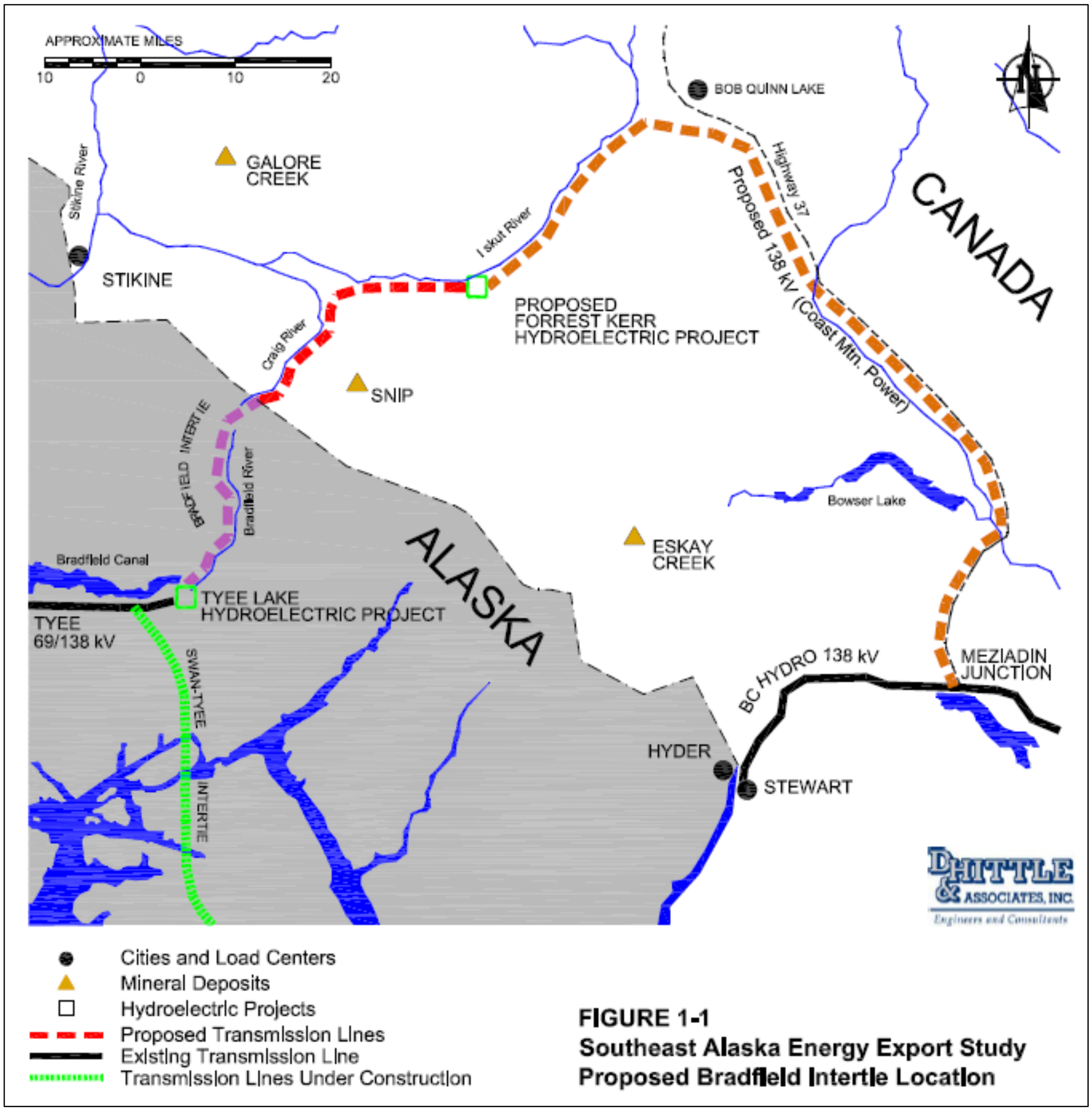

Figure 4: DHA conceptual map of AK-BC Intertie

Hatch adopts the DHA route. It does, however, update DHA assumptions regarding route access noting that only the first 2.5 miles are currently road accessible. In addition, while Hatch adopts most of DHA's Intertie specifications (138-kV line with 556.5 ACSR conductors) it uses H-frame wood structures, allowing for longer spans. Based on report findings, the system could export ~75 MW.

The B&V report does not develop or specify Intertie routing, technical specifications, or design concepts. The report lists the DHA and Hatch reports as primary references. Routing and specifications appear to follow those outlined, above.

DHA estimated capital costs to be $21.4 million ($2006), including a 30% contingency factor and 30% allowance for indirect costs. Estimate precision is characterized as being at a preliminary reconnaissance-level. Annual O&M costs is estimated at $318,850 for the first year and $281,000 for years in which only routine inspections, ROW clearing, and regular repairs occur. In years when catastrophic failures occur, projected annual O&M costs plus catastrophic failure costs range from $419,250 to $694,250. Catastrophic failures are projected roughly every 5 years.

Hatch estimates Intertie capital costs of $32 million ($2007). The higher figure is driven by the H-frame structure and recognized dependence on expensive helicopter access, inclusion of an additional transformer with associated breakers and switches at the existing Tyee switchyard, and experience with Alaska-specific conditions. Hatch also assumes 30% for contingency; indirect costs are 20%. Hatch adopts DHA's O&M costs, averaging them to an annual cost of $350,000.

B&V estimates Intertie capital costs of $41.7 million ($2011). B&V do not explain the revised capital estimate. We assume they are based on Hatch figures, account for cost escalation, and are adjusted by B&V based on subject matter expertise.

Both DHA and Hatch assume grant funding for the Alaska portion of Intertie capital costs. Accordingly, per-unit energy costs of transmission involve spreading annual O&M costs of $360,000 ($2007) over the energy transmitted (see Hatch; Table 6.1-2), or perhaps $.011/kWh assuming the entirety of Cascade Creek and Scenery Lake project output is exported. Presuming that Canadian governments did not similarly grant-fund their portion of the Intertie, a substantially larger tariff would be needed to move power to the Canadian transmission system for export.

B&V does not assume grant funding for the Alaska portion of the Intertie. Accordingly, per-unit energy transmission costs involve spreading annual O&M and annualized capital costs over the amount of energy transmitted. In addition, B&V recognizes that per-unit Intertie charges are uncertain, owing to unknown future Intertie use. Given a range of annual energy transmission (65,000-325,000 MWH, based on a power export range of 15-75 MWs and a load factor of 50%), per-unit charges range from $.058-$.12/kWh (assuming a 30-year fixed charged rate). (B&V, p. 12-54)

Intertie transmission costs also include the energy costs of transmission losses. Hatch assumed these to be 2%.

2.5 Outside Market Prices and Transmission Wheeling Costs: Value at the AK-BC Border

DHA estimates a Washington State export market price of $.060-.072/kWh. DHA assume that the price would remain the same for five years and then increase at the rate of inflation. Given then-applicable BCTC tariffs, DHA estimate BC wheeling charges of $.0051 per kWh; DHA assumes $.0020 per kWh over the existing transmission system in Southeast Alaska.

Hatch considers the possibility of power exports to both BC and PNW. It adopts the DHA price range ($.060-$.072/kWh) as proxy for BC/PNW wholesale market prices. Hatch supports the price range by pointing to then-recent market signals associated with BC Hydro and Pacific Northwest utility competitive power acquisitions. Hatch suggests that prices above this range might be supported, but would depend on market drivers such as greenhouse gas policy. In their economic analysis, in lieu of specifying transmission tariffs, Hatch assume a price for electricity at the Alaska border of $.060/kWh, thus allowing for up to $.012/kWh in transmission costs. Hatch posits $.010/kWh transmission costs to the PNW, and $.008/kWh to BC, suggesting a price for exported Alaska power that could fall within the competitive range.

B&V considers the economics of both power imports into and exports from SE AK over an Intertie. For the import scenario, B&V assumes power might be purchased in the PNW at $.070/kWh (within the same range used by Hatch). Broadly consistent with Hatch, B&V estimates wheeling and energy loss costs of $.009-.013/kWh based on BC Hydro and BPA wheeling tariffs.

For the export scenario, B&V adopts a particularly favorable export market price – the California Renewables Market Price Referent Value. The Referent Value was $.104/kWh for a 25-year firm power contract beginning in 2011.[11] No longer in operation, at the time of B&V's report the Referent Value was set by the California Public Utility Commission to provide a standing market signal for acceptable prices for utility purchases of renewable electricity that fulfill requirements of California's renewable portfolio standard (RPS). Materially higher than the average cost of wholesale power in California, B&V intends for the Referent Value to stand in for the best available market for Alaska hydropower. B&V reasons that if export sales of hydropower cannot be economically justified under the California RPS market then they are unlikely to be supported by other markets.

B&V estimates a range ($.015-.025/kWh) for wheeling costs and energy losses from the AK-BC intertie to California (based largely on BC Hydro and BPA tariffs). The range is substantially driven by assumptions as to the cost of line loss. The cost of line loss is, in turn, driven by physical losses of electricity to heat (a fixed percentage) multiplied by the value of that power – which B&V assumes to be $.050 - $.10/kWh.

2.6 Report Findings

DHA conducts an economic analysis of their four configuration cases. DHA's framework assumes grant funding of the Bradfield Intertie's construction, and estimates net revenues that could be used to pay for the costs of power generated in Southeast Alaska. The cumulative present value of net revenues over the 25-year period 2010 through 2034, is estimated to be $41 million, $184 million, $492 million and $580 million for the four cases, respectively. If separate tariffs were required for the 35-mile transmission segment between the AK-BC border and the BC Hydro transmission system, owing to the Forrest Kerr developer's ownership of that segment, then cumulative present value would be reduced by $25 million and $30 million.

DHA's results reveal relatively little. They suggest that under a range of scenarios ongoing Intertie operation and maintenance costs could be economically covered and "netback" revenue to hydropower operators would be positive. DHA do not assess whether their cumulative net revenue figures would be sufficient to pay for the infrastructure costs needed to generate and transmit Southeast hydropower.

Hatch finds that some projects might profitably export power. Based on assumed market prices, wheeling costs, and a capital recovery period that reflects private sponsorship, Cascade Creek, Whitman Lake and Scenery Lake project could do so. If generation costs are recovered over a 50-year period the number of hydro projects that might profitably export power increases to as many as seven (Table 3). However, such a lengthy amortization schedule would probably require government backing. This raises policy issues as to whether such hydropower capital investments are where the State would want to put its money.

Hatch finds project profitability to be highly sensitive to assumptions. For the reference case discount rate (6%), Cascade Creek and Scenery Lake could profitably export power under both low and high Southeast load growth scenarios. However, at higher discount rates of 8% and 10%, which in effect represent higher costs of capital, neither project could profitably export power. Similarly, relatively modest increases (20%) in project capital costs render power exports uneconomic. The key conclusion to draw is that the earlier-noted substantial uncertainty in project capital costs, costs of capital, and capital recovery period, generate substantial economic risk of inadequate netback value to the hydropower project sponsor. For those risks to be managed, a well-defined and highly focused business plan would be needed.

[11] Under a complex regulatory formula, meant to emulate the long-term cost of gas fired generation, a host of values affected the Referent value. They included the date by which a resource was brought online and the length of contract both affected Referent values, as well as projected natural gas prices and interest rates.

B&V find that exports of hydropower could probably not be profitably pursued. The conclusion follows from two critical assumptions. First, estimated capital costs of hydropower project construction had increased since the Hatch report. Second, B&V assumes that Intertie capital costs must be recovered in rates. We consider each in turn.

As noted earlier, 50-year capital recovery significantly reduces per unit hydropower costs compared with 20-year capital recovery. Nevertheless, even with 50-year cost recovery, B&V expects the Whitman Lake project to cost around $.110/kWh, and the Cascade Creek to come in at $.103/kWh.[12] Given robust California RPS prices, Southeast "net back" prices range from $.021-$.077/kWh (a market price of $.104 minus wheeling costs of $.015-$.025 and intertie costs of $.012-$.058/kWh). At best, therefore, energy costs from potential hydroelectric projects in SE AK would need to be less than $.077/kWh to support economic export over an Intertie. At worst, the hydro projects would need to generate power for less than $.021/kWh. The "net back" value is, therefore, insufficient to cover generation costs.

The prospect for Intertie export improves only modestly if we relax the assumption that Intertie costs are privately funded and instead assume grant funding of the Intertie. Netback values for the low-volume export case would increase by about $.05/kWh, while for the high-volume case they would increase by about $.10/kWh. Accordingly, energy costs from potential hydroelectric projects in SE AK could rise to $.071-$.087/kWh, from the $.021-$.077/kWh range implied by private Intertie funding. This range is still substantially inadequate to cover hydropower costs.

But the economic case for an Intertie is even worse. Further undermining the case against export, B&V notes material costs that would be realized, but that were not included in its analysis, include:

- Costs of interconnecting hydroelectric projects to the AK-BC Intertie.
- Costs of any required SEAPA system improvements.
- Costs of the marketing and dynamic scheduling of power for export.
- Costs associated with temporary inability to meet supply contract.

In short, B&V find that the price disequilibrium between SE AK and Outside markets appears inadequate to justify an Intertie project based on export.

B&V also consider whether importing hydropower might make economic sense. They conclude it does not. Given electricity markets in the Pacific Northwest (Hatch's figure of $.07/kWh), wheeling costs of $.09-$.013/kWh (for Bonneville Power Administration Main System and the BC Hydro system, without and with electricity losses), and $.058/kWh for using the AK-BC Intertie (B&V assume relatively low levels of throughput required to meet SEAPA power needs), B&V develop cost of imported power of $.137-$.141/kWh. This is greater than the cost of generation of several different hydro projects considered by Hatch.

Moreover, B&V argue that the actual cost of delivered power is likely to be greater than this. Their estimate does not include:

- Costs of moving power on the Canadian portion of the AK-BC Intertie;
- Costs associated with any required SEAPA transmission system improvements;
- Costs of additional transmission segments (if any) needed to be constructed to move power from the SEAPA system to local load centers.

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[12] It appears that B&V point to updated cost estimates for these two projects because: a) they exist; b) Whitman Lake was the least expensive of the projects modeled by Hatch; and c) Cascade Creek was considered by Hatch to be a critical export project given its substantial project output.

If B&V's assumption that an Intertie would be privately sponsored is relaxed, and government funding is instead assumed, then calculated cost of wheeled power drop to $.087-$.091/kWh. Does this mean that an Intertie might make sense for power imports? Probably not, at least given B&V's assumptions and estimates.

As noted, costs of moving power on the Canadian portion of the AK-BC Intertie unavoidably remain. If the BC portion were privately funded then these could be expected to be of the same general size as the Alaska portion of the Intertie, e.g. roughly $.04-$.05/kWh for capital costs alone. Imported power costs would therefore, at minimum, exceed $.125/kWh –more than new-build Alaskan hydro. If the BC portion were grant funded (necessary to enable imported power to compete) then the State of Alaska would be the natural party to provide subsidies. It is possible that the State would choose to pay for assets in a foreign country. However, the scale of required grants (roughly $80 million, for combined AK and BC Intertie portions) raises questions as to whether hydropower projects within Alaska might instead be better candidates for State grant funds. Grant funding might be used to underwrite substantial amounts of new local power at comparatively lower cost (see, e.g., Table 4 and Table 5).

3.0 Current Economic Conditions and the AK-BC Intertie

On the whole we find B&V's logic regarding Intertie import and export cases to be sound. We now assess, based on publicly available information, whether the assumptions underpinning B&V's analysis remain sufficiently valid. If so then B&V's conclusions should also be maintained.

As noted before, the economic case for an Intertie requires sufficient price disequilibrium between SE AK and Outside markets. It therefore implicates three basic cost elements:

- Per-unit electricity prices in SE AK, as affected by potential changes in hydropower construction cost or regional energy demand;
- The cost of the intertie itself, divided by the amount of power that would flow over the intertie;
- Per-unit electricity and power prices in the Outside market, plus any additional wheeling costs associated with moving power between the AK-BC Intertie and the Outside market.

We assess whether any of these appear to have changed sufficient to consider re-examining the economic justification of Intertie construction.

3.1 Southeast Alaska Market

We assess whether SE AK demand appears to significantly differ from the scenarios developed by B&V in the Southeast IRP. Were this the case then it would call into question the number and type of hydropower resources that might be needed or the amount of power that imports could potentially economically satisfy. After all, B&V notes that IRP's use relatively conservative demand projections, while Economic Development Plans – sometimes used to help justify development of large projects – tend to involve more optimistic projections of possible demand. As it happens, however, regional demand appears substantially in line with B&V's characterizerization.

IRP expectations for peak demand and annual energy were compared with 2011, 2012 and 2013 utility data for some locations based on data availability. (Table 6) The utility data indicates that peak demand and annual energy deliveries have been within the Low and High scenario forecasts.

Demand growth appears mostly driven by expected factors. Significant numbers of households continue to convert their heating systems from fuel to electricity, a trend highlighted in the Southeast IRP. In Juneau, many new or renovated commercial buildings are planning to use electricity as their heat source.

Information published by the Southeast Conference indicates that population, employment and cruise ship visitor trends are modestly rising. Meanwhile, Alaska Ship and Drydock implemented a $31 million renovation of its facility in Ketchikan, introducing the potential for some increased electrical load in the future, relative to baseline assumptions incorporated in the Southeast IRP.

Mining demand for electricity does not appear to change the general expectations contained in the IRP. Of the two producing mines in SE Alaska, the Greens Creek Mine already receives some hydropower under an interruptible load contract, and Kensington is not grid-connected. Prince of Wales Island is the most likely region for this future activity. Accordingly, absent substantial additional SE AK transmission investment that is itself challenged, mining loads are unlikely to affect Intertie economics. We note that additional barriers to significant growth in mining-related electrical demand include permitting and public acceptance issues, and ore prices.

Our review did not identify any significant line item changes to the load analysis.

Table 6: Comparing IRP Electrical Loads with Current Utility Data

Data	YEAR	KETCHIKAN SAXMAN	PETERSBURG	WRANGELL	PRINCE OF WALES REGION	WHALE PASS	HAINES / SKAGWAY	JUNEAU AREA	ANGOON	HOONAH	KAKE	KLUKWAN	CHILKAT VALLEY	METLAKATLA	SITKA	YAKUTAT	GUSTAVUS	ELFIN COVE	PILICAN
PD-L	2011	30.8	10.6	6.6	5.1	0.1	5.6	80.9	0.4	0.8	0.4	0.1	0.3	4.5	23.7	1.4	0.4	0.1	0.2
PD-L	2012	35.6	11.2	6.7	5.4	0.1	5.7	82.8	0.4	0.8	0.4	0.1	0.3	4.7	24	1.4	0.4	0.1	0.2
PD-L	2013	36	11.3	6.7	5.5	0.1	5.8	83.4	0.3	0.8	0.4	0.1	0.3	4.8	24.1	1.4	0.4	0.1	0.2
PD-L	2014	36.5	11.4	6.6	5.6	0.1	5.9	84	0.3	0.8	0.4	0.1	0.3	4.7	24.2	1.4	0.4	0.1	0.2
PD-L	2015	36.9	11.5	6.4	5.6	0.1	5.9	84.3	0.3	0.8	0.4	0.1	0.3	4.7	24.2	1.3	0.4	0.1	0.2
PD-H	2011	30.1	11	7.6	5.2	0.1	5.6	81.3	0.4	0.8	0.4	0.1	0.3	4.5	23.7	1.4	0.4	0.1	0.2
PD-H	2012	36	11.3	9.3	5.5	0.1	5.8	84.2	0.4	0.9	0.4	0.1	0.3	4.7	24.3	1.4	0.4	0.1	0.2
PD-H	2013	36.8	11.6	9.5	5.7	0.1	5.9	85.7	0.4	0.9	0.4	0.1	0.3	4.9	24.6	1.4	0.4	0.1	0.2
PD-H	2014	37.8	11.8	9.5	5.8	0.1	6.1	87.5	0.4	0.9	0.4	0.1	0.3	4.9	25.1	1.4	0.4	0.1	0.2
PD-H	2015	38.8	12.1	9.6	6	0.1	6.3	89.3	0.4	0.9	0.4	0.1	0.3	5	25.4	1.4	0.4	0.1	0.2
PD-R	2011	30.8	10.6	7.6	5.2	0.1	5.7	80.9	0.4	0.8	0.4	0.1	0.3	4.5	23.7	1.3	0.4	0.1	0.2
PD-R	2012	35.6	11.2	9.3	5.5	0.1	5.8	82.9	0.4	0.8	0.4	0.1	0.3	4.7	24.1	1.3	0.4	0.1	0.2
PD-R	2013	36.1	11.3	9.3	5.6	0.1	5.9	83.6	0.3	0.8	0.4	0.1	0.3	4.8	24.1	1.3	0.4	0.1	0.2
PD-R	2014	36.7	11.5	9.3	5.7	0.1	6	84.5	0.3	0.8	0.4	0.1	0.3	4.8	24.3	1.3	0.4	0.1	0.2
PD-R	2015	37.3	11.7	9.2	5.8	0.1	6.1	85.4	0.3	0.8	0.4	0.1	0.3	4.8	24.4	1.3	0.4	0.1	0.2
PD-A	2011			9.0				73.5											
PD-A	2012			8.0				79.6											
PD-A	2013			8.5				68.2											
AE-L	2011	189,796	54,750	30,205	29,089	266	28,776	418,018	1,809	4,267	2,203	375	1,218	20,511	121,751	6,418	2,245	337	883 416
AE-L	2012	202,663	55,403	30,566	30,855	274	29,285	428,206	1,786	4,261	2,184	378	1,241	21,302	123,559	6,379	2,285	330	969 415
AE-L	2013	205,151	56,120	30,440	31,347	281	29,780	431,056	1,763	4,254	2,165	380	1,263	21,686	123,732	6,338	2,302	323	1,015 415
AE-L	2014	207,865	56,755	30,020	31,605	289	30,185	434,027	1,739	4,238	2,140	381	1,282	21,597	124,457	6,284	2,289	315	1,009 413
AE-L	2015	210,027	57,251	29,380	31,911	295	30,443	435,824	1,714	4,209	2,107	379	1,296	21,434	124,337	6,210	2,264	307	998 411
AE-R	2011	189,796	54,750	30,205	29,089	266	28,776	418,018	1,809	4,267	2,203	375	1,218	20,511	121,751	6,418	2,245	337	883 416
AE-R	2012	202,897	55,461	30,658	30,916	274	29,343	428,700	1,787	4,267	2,188	379	1,243	21,331	123,684	6,388	2,290	330	971 416
AE-R	2013	205,712	56,258	30,658	31,494	282	29,920	432,233	1,765	4,267	2,173	382	1,267	21,758	124,029	6,357	2,313	324	1,020 416
AE-R	2014	209,139	57,069	30,505	31,939	290	30,505	436,687	1,743	4,267	2,159	386	1,293	21,758	125,127	6,327	2,313	317	1,020 416
AE-R	2015	212,635	57,894	30,353	32,599	299	31,098	441,237	1,721	4,267	2,145	389	1,318	21,758	125,692	6,296	2,313	311	1,020 416
AE-H	2011	189,801	54,752	34,504	29,382	266	28,776	418,031	1,809	4,267	2,203	375	1,218	20,512	121,754	6,418	2,247	337	883 416
AE-H	2012	204,809	56,015	42,573	31,527	277	29,633	432,919	1,805	4,310	2,211	383	1,255	21,538	124,912	6,453	2,315	334	980 420
AE-H	2013	209,708	57,386	43,145	32,437	288	30,512	440,841	1,802	4,354	2,219	390	1,293	22,186	126,517	6,487	2,361	330	1,039 424
AE-H	2014	215,310	58,793	43,466	33,225	299	31,414	449,823	1,798	4,398	2,227	397	1,332	22,409	128,910	6,521	2,385	327	1,049 429
AE-H	2015	221,074	60,236	43,749	34,248	311	32,351	459,040	1,793	4,443	2,235	405	1,372	22,634	130,790	6,556	2,410	324	1,060 433
AE-A	2011			34,157				364710											
AE-A	2012			35,759				399144											
AE-A	2013			37,694				377005											

In addition to revisiting Southeast demand, we also assess whether there were changes to the cost of new-build hydropower supply. In its screening assessment, B&V indicate that estimated construction costs for SE hydropower projects were generally – and in some cases significantly – higher than what Hatch had earlier found (Table 5). Public sources of updates to those cost estimates are scant. The only update found was for Mahoney Lake. In a preconstruction funding request to the Alaska Legislature, the City of Saxman pegs total project cost at $51 million. This is the upper end of the cost uncertainty band that B&V provided.[13] We therefore find no reason to think that hydropower project costs have declined since the Southeast IRP was finished.

3.2 Intertie Costs

There have been developments since the Hatch report was completed that directionally improve Intertie feasibility. Transmission infrastructure within BC has increased, and moved towards SE AK. At the time of Hatch's analysis, the Northern Transmission Line (NTL) – running from Meziadin Junction substation to north to the Bob Quinn substation – was merely "proposed" (Figure 1 and Figure 2). The NTL's construction is now nearly complete, and full commissioning is scheduled for June 1, 2014. As well,

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[13] See 2013 Legislature's Total Project Snapshot report 59189v1, dated 5/9/2013, for award to the Department of Commerce, Community and Economic Development.

construction of the Forrest Kerr Hydroelectric Power Project is now underway (Alta Gas, 2013). That project has a capacity of 195 MW and, most important for the Intertie, entails construction of a new 287 kV transmission interconnect to the NTL at Bob Quinn. This will reduce by approximately 37 km (nearly half) the need for new construction on the BC side of the border. (Taltan Central Council, 2014) (Figure 2)

Some of the necessary conditions for an Intertie to be feasible have therefore been realized. Moreover, the BC regulatory regime would not impose wheeling costs associated with NTL use that are on top of the general BC Transmission tariff. (While actually helpful these developments do not alter previously calculated transmission costs via an AK-BC Intertie, because neither B&V nor Hatch costed NTL transmission service.) Finally, power exported from SE AK and wheeled across the BC Hydro system may qualify for discounted transmission rates. While B&V's analysis assumes transmission charges of $.0054/kWh, and current non-discounted BC transmission costs are now $.0068/kWh (including point-to-point tariff, and required scheduling service and reactive power charges), discounting would reduce costs to $.0033.[14]

Meanwhile, the market has also offered negative cost signals. While to our knowledge Intertie cost estimates have not been updated, the cost escalation that the NTL experienced is not encouraging. In 2007 (the same era as Hatch's estimate of Intertie costs), at the time of the NTL Project's EIS, the projected cost was estimated at $404 million. (Rescan, 2007; p. 4-51) By 2013, at time of supplemental tariff filing, the estimated cost had increased to $561 million. (BCUC, 2013; Appendix A, p.1). As of this writing, with completion mere months away, total CapEx is expected to be $736-$746 million.[15] Intertie economics, such as they are, would be significantly further undercut if Intertie capital costs were to experience a cost trajectory that resembles the NTL's.

3.3 Outside Market Prices

Determining appropriate benchmarks for Outside electricity prices is not a simple task. Any grid-interconnected point is a potential market. Absent comprehensive system modeling of future prices at numerous locations, analysis must be constrained to a few obvious market centers. In what follows we consider, in turn, the British Columbia, Alberta, Pacific Northwest and California markets with an eye towards significant upward (for the export case) or downward (for the import case) price trends or market developments. Both legal prohibitions and regional prices appear to undermine Intertie economics.

3.3.1 British Columbia Market

From a physical and cost perspective British Columbia would be the ideal place to market Alaska hydropower. Sales there would incur the least amount of transmission loss and transmission charges. However, sales for BC consumption are essentially foreclosed.

The Province's 2010 Clean Energy Act requires BC to become self-sufficient with regard to electricity generation. As well, electricity supply additions are expected to come from renewable resources. In pursuit of this, and consistent with regulatory exemptions granted under the Act, BC Hydro has:

- Started adding Unit 5 (completion expected 2014) and Unit 6 (expected in 2015) to the Mica hydro project, which will add over 1,000 MW of capacity at a cost of $700 million;

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[14] See BC Hydro's transmission tariff, particularly Schedules 1, 3 and 4, which is currently available at http://transmission.bchydro.com/regulatory_filings/tariff/tariff_documents/open_access_tariff.htm.

[15] Northwest Transmission Line Project; https://www.bchydro.com/content/BCHydro/en/energy-in-bc/projects/ntl.html

- Continued to advance the Site C hydro project on the Peace River, with 1,100 MW of capacity. Public hearings have been conducted and environmental reviews are expected to be completed late in 2014;
- Pursued regulatory approvals for the Unit 6 of the Revelstoke project, which could provide an additional 500 MW of hydropower capacity, if needed, by 2020 (BC Hyrdo, 2013);
- Completed, in 2011, a competitive acquisition process for independently produced biomass energy that will deliver 86 MW of firm power at a cost of $.115/kWh (BC Hydro, 2012);
- Completed, in 2010, a Clean Power Call RFP for contracts for purchase of renewable energy from IPPs, with in-service dates of 2016 or earlier.

In total, since 2006 deals with Independent Power Producers have secured sufficient renewable energy capacity to provide the province to supply nearly 8,500 GWH of energy annually. There is little reason to expect the Clean Energy Act's self-sufficiency requirements will need to change for feasibility reasons.

BC Hydro's competitive acquisition in 2010 of renewable power under the Clean Energy Act is instructive with regard to general renewable energy market trends. Twenty-five energy purchase agreements were signed to provide 3,265 GWh of firm power, with about half of that figure coming from local hydropower.[16] Although prices for each individual project bid are confidential, the average cost of energy across winning bids was about $.0995 per kWh.[17] This raises two related points. First, renewable energy market trends in British Columbia are broadly in agreement with (if somewhat below) most recent SE AK hydropower projects cost estimates. This is as one might expect given similar technology, resource size, and the like. Second, there is little reason to believe that BC would have economic need to import SE AK hydropower, even were the self-sufficiency requirements of the Clean Energy Act to be vacated. Bids in the Clean Power Call – offers exceeded need by over 13,000 GWh – arguably reinforces this conclusion.

If BC is an unlikely market for the export of SE AK power, could it nevertheless be an economic source for SE AK power imports? This does not seem out of the realm of possibility. The Clean Energy Act articulates a goal of BC's becoming a net exporter of green energy, and BC's integrated resource planning process must address export needs and opportunities.

However, market signals do not appear to support exports to Alaska. In the 2010 Clean Power Call accepted bid energy prices ranged $.076 to $.119/kWh, with firm power ranging from $.105-$.134/kWh. Economic theory suggests that remaining hydropower opportunities within BC are likely to be somewhat more expensive than the top end of these ranges. (If there were more cost-effective opportunities within BC, one would suppose that these projects would have been bid.) If theory is correct, then after Intertie charges the cost of imported wholesale firm power in SE AK will top $.13/kWh. This would appear to exceed the cost of within-region hydropower.

3.3.2 Alberta Market

The province of Alberta is another conceivable outlet for Alaska hydropower. Generation prices there are established on a competitive exchange, rather than via long-term contract, with a non-profit independent system operator making dispatch decisions based on rank-order bids for supply. In consequence they evidence substantial volatility, both within (Figure 5) and across (Figure 6) months.

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[16] See, for example, BC Hydro , 2010.

[17] The average accepted bid price for firm energy was higher than this. We report expected effective rate for non-firm energy, however, because Hatch and Black and Veatch both report non-firm rather than firm Southeast energy costs.

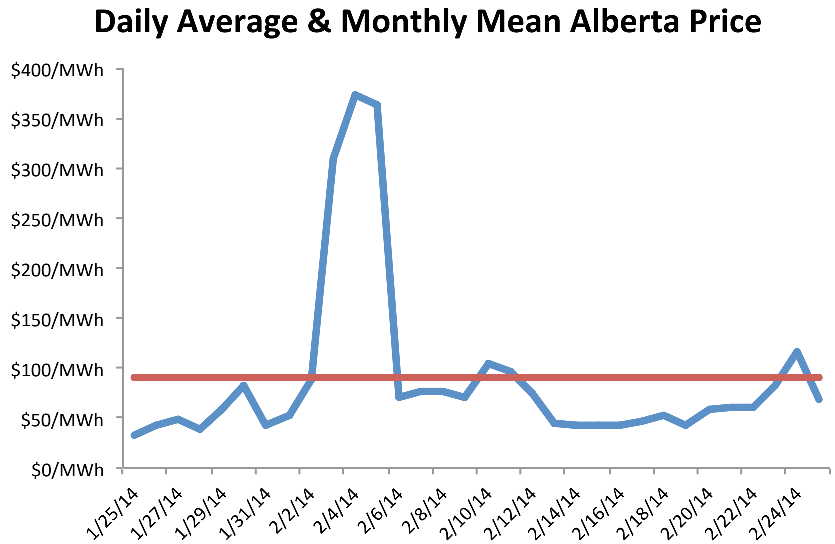

Figure 5: Daily average and monthly mean electricity prices, 1/25/2014 - 2/24/2014. Data from AESO (2014).

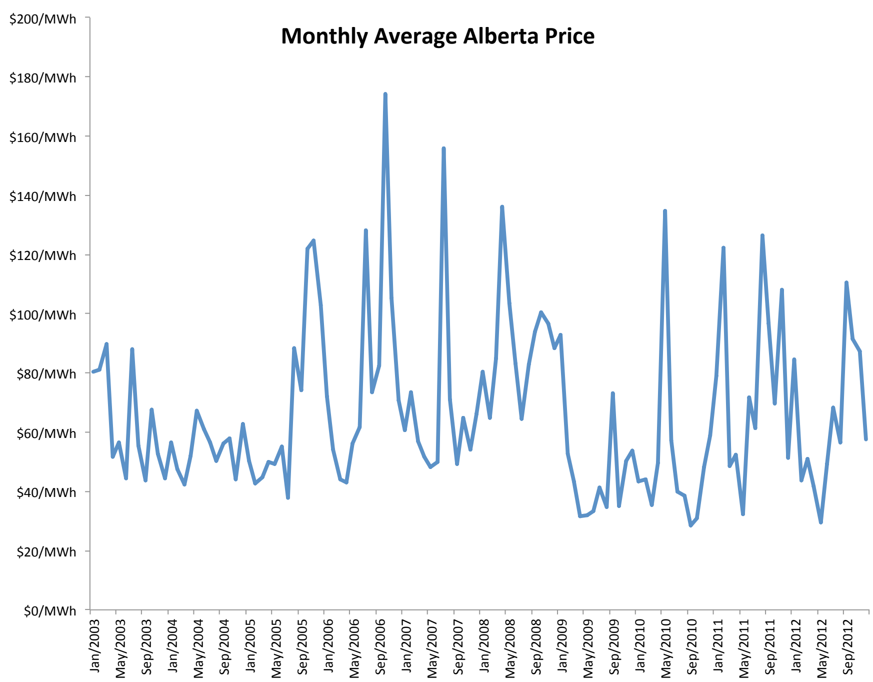

Figure 6: Monthly average Alberta electricity prices, 2003-2012. Data from AESO (2014)

Such volatility imposes considerable risk for any would-be hydropower developer, whose costs are mostly fixed. Even aside from the volatility, the average price over the last ten years is under $.070/kWh – insufficient to cover Southeast generation costs (not including wheeling charges, and the like).

The relatively low cost of power in Alberta could conceivably make importing power across an AK-BC Intertie attractive. However, importing power from Alberta would impose additional transmission wheeling charges that appear likely to eat up potential savings. The Alberta Electric System Operator's average transmission charge over the next 15 years is about $.034/kWh. Accordingly, to get power to the Alberta-BC border would cost more than $.095/kWh, where a new set of wheeling charges of at least $.003/kWh (once scheduling service and reactive power charges are added in) would apply to get power to the Intertie. Accordingly, even assuming full grant funding of at least $80 million to pay for an Intertie's capital costs, imported Alberta power seems likely to average over $.13/kWh. This appears unattractive compared with existing SE AK options.

3.3.3 Pacific Northwest Market

Both Hatch and B&V assume a PNW wholesale energy price of about $.07/kWh (2007$). This figure is premised on an assessment of power costs from combined cycle combustion turbine generators, which are assumed to be the marginal source of supply. (Hatch, 2007). It is sensitive, of course, to expected natural gas costs.

The $.07/kWh figure appears, as reference value, to remain broadly within the ballpark. For example Avista, a Washington State based electric utility, projects in their integrated resource plan that gas-fired generation coming on line between 2015-2017 would have a levelized cost of $.07-$.08/kWh. (Avista, 2013a) Given their portfolio options, it appears that gas combustion technology is viewed as a particularly favorable technology, given their resource options and expected supply and demand trajectories. (Avista, 2013b)

The upshot is that the outlook in the Pacific Northwest market appears to have changed little from the time when Hatch first assessed it. Accordingly, there seems to be little reason to doubt or reconsider B&V conclusions regarding the economic feasibility of Intertie-facilitated export to or import from the Pacific Northwest market, absent Intertie grant funding.

3.3.4 California Energy Market

B&V based their Intertie screening export case on the California market. They did so because California has particularly aggressive goals for the proportion of renewable energy that should supply the market. Given that renewable energy tends to be more expensive to generate than energy from traditional fossil resources, it offers the possibility of a more lucrative export market.

To meet its aggressive renewable portfolio goals California has adopted a series of policies for green energy procurement. These have changed since B&V's report. One of the more notable changes, included in legislation that increased California's renewable portfolio standard to 33% by 2020, is that only hydroelectric projects of 30 MW or less count towards the goal (CPUC, 2012). This would disqualify some potential SE AK hydro projects from providing power for export; the Cascade Creek project (with a capacity of 45 MW) is one that Hatch counted on to underpin export but that would be excluded from the RPS market.

Meanwhile, California energy policy has continued to evolve. The "referent price", upon which B&V base their Intertie economic screening, no longer plays a role in RPS bid evaluation. Meanwhile, while the formula-based referent price – $.104/kWh at the time of B&V's analysis – no longer provides a useful benchmark, a competitive bid market continues. The RPS bid process continues to mature, along with the renewable energy industry. In 2012 the average price for the top 25% of bids was under $.10/kWh (only the top 2% of all proposals are shortlisted for consideration), and overall bid prices have dropped 30% since 2009. (CPUC, 2012). The weighted average of approved contracts for green power in 2012 was about $.9/kWh.

This softer pricing signal is echoed in the new standard offer contract to purchase wholesale distributed generation from projects under 3MW. As of 2013, such resources can be purchased under a standard Feed-In Tariff. The ReMAT (or renewable energy market adjusting tariff), is adjusted periodically by the California Public Utility Commission to reflect the avoided cost of fossil power and by competitive qualifying renewable energy bids. The most recent Feed-In Tariff is $.08923/kWh. (CPUC, 2013)

In summary, California has become a less attractive market for potential export of Southeast hydropower. Larger projects such as Cascade Creek and Scenery Lake would be simply disqualified from competing in the lucrative RPS market. And, while the RPS standards have gotten more aggressive, the renewable energy industry is maturing and generation prices are dropping. Prices have eroded over $.01/kWh in the last few years.

4.0 Conclusion

In their high-level screening of AK-BC Intertie economics B&V notes that changes in certain conditions may warrant a re-examination of their conclusions. They deem the following to be particularly salient:

- Prices in potential export markets in North America (principally BC, PNW, or the Southwestern region of the United States) might increase significantly, for any number of reasons;
- Costs for new SE AK generation might increase substantially, thereby enabling SE AK imports. This could result from either local project cost or load increases.
- State decision makers could consider an Intertie investment to be a "public good", and deem the Intertie justified on policy rather than standard economic grounds.

We have addressed the first two sets of these factors – prices in potential export markets, and estimated costs of Southeast hydro project construction – in light of current conditions. Doing so reinforces B&V's conclusions.

The cost to produce electricity from the two most favorable Southeast Alaska hydro projects appears to be at least $.10 - $.11/kWh. This range assumes 50-year amortization of project costs, and low project rates of return. It is probably close to a lower bound on what is economically feasible.

This lower-bound cost exceeds the calculated netback value from power exports. Table 7 summarizes six different potential power export cases that span a wide range of key assumptions. Case 1 replicates B&V's work, with a correction for its calculation of the value of electricity lost through resistant heat in transmission (line loss). While B&V assume a market value for electricity lost to heat, line losses in Table 7 are based on actual cash-flow costs of transmission for electricity that cannot be marketed. That is, because electricity is lost to heat on each successive transmission segment, some electrons "pay" transmission tariffs on earlier segments but never "arrive" at destination. Because the fixed size of the SE AK power market implies that the opportunity cost for exported power is essentially zero, there is no reason to ascribe value to the power lost in transmission beyond having to pay for transmission for electricity than cannot ultimately be sold. The practical implication of this correction, in general, is to reduce the cost of line loss and to improve export economics compared with B&V's framework.

Changes in assumptions from one case to the next are highlighted in orange in Table 7. Cases 2-6 build on Case 1 but model the reduced Intertie tariffs that result from higher assumed throughput. This increases the value of exports compared to Case 1, and thus improves Intertie economics. Cases 3-6 explore alternative export markets for SE AK power. They contain current data on market prices, tariffs for existing transmission, and line losses to the California, PNW, and Alberta electricity markets.[18] Cases 4-6 assume that the Intertie's capital costs are publicly funded. Public funding reduces AK-BC transmission costs, and directionally (if insufficiently) improves the economic viability of SE AK hydropower economics.

Table 7: Summary of Hydropower Export Economics: Netbacks appear inadequate to encourage new construction

Case 1: Black and Veatch, low export		*Case 3: Update, CA Market*		*Case 5: Update, PNW Market*	
California 'referent' Sales price	0.104	California 'referent' Sales price	0.090	PNW Market Price (Avista IRP)	0.080
BPA - southern intertie	0.004	BPA - southern intertie	0.002	BPA - southern intertie	0.000
BPA - main system	0.004	BPA - main system	0.002	BPA - main system	0.002
BC Hydro (100% load factor	0.005	BC Hydro (100% load factor), discounted	0.003	BC Hydro (100% load factor), discounted	0.003
AK - portion of AK-BC Intertie, 7.4 MW of power	0.058	AK - portion of AK-BC Intertie, 37.1 MW of power	0.012	AK - portion of AK-BC Intertie, 100% public funding, 37.1MW of power	0.002
Transmission subtotal	0.071	Transmission subtotal	0.019	Transmission subtotal	0.007
Line loss cost	0.009	Line loss cost	0.002	Line loss cost	0.001
Netback value	**0.024**	**Netback value**	**0.069**	**Netback value**	**0.072**

Case 2: Black and Veatch, high export		*Case 4: Update, CA, Intertie Subsidy*		*Case 6: Update, Alberta Market*	
California 'referent'	0.104	California 'referent' Sales price	0.090	Alberta Market Price	0.070
BPA - southern intertie	0.004	BPA - southern intertie	0.002	Alberta Transmission	0.003
BPA - main system	0.004	BPA - main system	0.002	BPA - main system	0.000
BC Hydro (100% load factor	0.005	BC Hydro (100% load factor), discounted	0.003	BC Hydro (100% load factor), discounted	0.003
AK - portion of AK-BC Intertie, 37.1 MW of power	0.012	AK - portion of AK-BC Intertie, 100% public funding, 37.1MW of power	0.002	AK - portion of AK-BC Intertie, public funding of entire intertie, 37.1MW of	0.002
Transmission subtotal	0.024	Transmission subtotal	0.009	Transmission subtotal	0.008
Line loss cost	0.003	Line loss cost	0.001	Line loss cost	0.001
Netback value	**0.077**	**Netback value**	**0.080**	**Netback value**	**0.061**

For all three potential export markets, at both sets of Intertie throughput assumptions, and regardless of whether the Intertie is publicly funded, the netback value of SE AK hydropower exports is inadequate to support the cost of new project construction. That is, the netback value of power exports is less than the cost of electricity from the most favorable new hydropower projects, even given favorable assumptions ($.10-$.11/kWh). Accordingly, power exports do not provide economic justification for Intertie construction.

The conclusion is reinforced by the fact that a series of potentially substantial costs will be incurred but have not been subtracted from modeled netback values. These costs include building the Canadian portion of the AK-BC intertie and necessary transmission infrastructure from new hydro projects to the Intertie; reserving transmission capacity that is unlikely to always be fully used (which raises effective transmission rates); and making other required SEAPA system improvements.

We also examine a number of SE AK power import cases. (Table 8) Only five import scenarios are considered, as (following B&V) we recognize that foreseeable additions to SE AK power needs will almost certainly be modest. This makes unrealistic a "high volume" power import case. (Higher throughput cases do not directionally change conclusions regarding the economic feasibility of power imports.) As with Table 7, changes in assumptions from one case to the next are highlighted in orange.

Case 1 replicates B&V's work, again with correction to calculation of the cost of line loss. Cases 2-5 update B&V's work to reflect current market prices and transmission tariffs. Power imports from both the PNW

[18] See discussion of Section 3.3 for current tariff references, B&V Table 12-15 for line loss percentages for Outside transmission segments, and Hatch for assumed Intertie line loss.

(Cases 1, 2, and 3) and Alberta (Cases 4 and 5) markets are considered. The effect on Intertie import economics of private (Cases 2 and 4) and public (Cases 3 and 5) funding is also assessed. If the Intertie were fully grant funded, at a cost of perhaps $80 million, then it appears that the Intertie might support the economic importation of power from the PNW market. However, if the goal is to provide cheap power to SE AK, fully subsidizing local hydro projects might be a better way to provide similar amounts of power at significantly less expense (see Tables 4 and 5, above).

Table 8: Summary of Hydropower Import Economics: Import prices appear to exceed local value

Case 1: Black and Veatch	
PNW Market Price	0.070
BPA - main system	0.004
BC Hydro (100% load factor)	0.005
AK - portion of AK-BC Intertie, 7.4 MW of power	0.058
Transmission subtotal	0.067
Line loss cost	0.008
SE AK Import price	**0.146**

Case 2: Update, PNW Market	
PNW Market Price	0.08
BPA - main system	0.002
BC Hydro (100% load factor), discounted	0.003
AK - portion of AK-BC Intertie, 7.4 MW of power	0.058
Transmission subtotal	0.063
Line loss cost	0.008
SE AK Import price	**0.151**

Case 3: Update, PNW, Intertie Subsidy	
PNW Market Price	0.080
BPA - main system	0.002
BC Hydro (100% load factor), discounted	0.003
AK - portion of AK-BC Intertie, 100% public funding, 7.4MW of power	0.002
Transmission subtotal	0.007
Line loss cost	0.001
SE AK Import price	**0.088**

Case 4: Update, Alberta Market	
Alberta Market Price	0.070
Alberta Transmission	0.034
BPA - main system	0.000
BC Hydro (100% load factor), discounted	0.003
AK - portion of AK-BC Intertie, 7.4 MW of power	0.058
Transmission subtotal	0.095
Line loss cost	0.012
SE AK Import price	**0.177**

Case 5: Update, Alberta, Intertie Subsidy	
Alberta Market Price	0.070
Alberta Transmission	0.034
BPA - main system	0.000
BC Hydro (100% load factor), discounted	0.003
AK - portion of AK-BC Intertie, 100% public funding, 7.4MW of power	0.002
Transmission subtotal	0.039
Line loss cost	0.005
SE AK Import price	**0.114**

Despite these results, it may turn out that the state is willing to subsidize the AK-BC Intertie. Economic viability may be a secondary consideration if transmission infrastructure is deemed necessary for regional development, or serves other broad policy goals. Nevertheless, because state funds are limited, it may still be reasonable to assess whether a subsidized Intertie better serves regional aspirations better than subsidies for other local projects.

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