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Integrated Resource Plan

Appendix 3A-27

2013 Resource Options Report Update

Run-of-River Report

**2013 Update Memorandum
and
2010 Report**

Appendix 8-A is comprised of two parts:

Part 1: 2013 Resource Options Report Update – Run-of-River Technical Memorandum

Run-of-River Hydroelectric Resource Assessment for British Columbia 2013 Revisions (June 2013)

During the process of preparing the run-of-river data for the BC Hydro August 2013 Integrated Resource Plan, Kerr Wood Leidal Associates Ltd. (KWL) identified that some items from its 2010 run-of-river report required revisions. This technical memorandum provides an overview of those revised items.

Part 2: 2010 Resource Options Report – Run-of-River Report

Run-of River Hydroelectric Resource Assessment for British Columbia 2010 Update (March 2011)

In 2010, BC Hydro commissioned KWL to complete an update to the 2007 inventory of run-of-river hydroelectric potential in British Columbia.

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Technical Memorandum

DATE: June 20, 2013

TO: Nan Dai, BC Hydro
Ellen Feng, BC Hydro

FROM: Colleen O'Toole, P.Eng.
Stefan Joyce, P.Eng.

RE: **RUN OF RIVER HYDROELECTRIC RESOURCE ASSESSMENT FOR BRITISH COLUMBIA**
2013 REVISIONS
Our File 0478.133-300

Introduction

In 2010, BC Hydro commissioned Kerr Wood Leidal Associates Ltd. (KWL) to complete an update to the 2007 inventory of run-of-river hydroelectric potential in British Columbia. In advance of the 2013 Integrated Resource Plan process, BC Hydro sought further data for analysis. During the data extraction for BC Hydro some items requiring revision were identified. This technical memorandum provides a discussion of the revisions made and provides an update on the inventory of British Columbia's run-of-river hydroelectric potential.

Discussion of Revisions to Run of River Inventory Analysis

The following revisions were made to the 2010 Run-of-River Hydroelectric Resource Assessment (2010 RoR Update):

Penstock Friction

In the process of this work KWL found that the penstock friction calculation needed to be revised. In most cases the penstock frictional losses formulation was underestimating the headloss and hence overestimating the net capacity (MW). In a few cases the friction was overestimated and the net capacity underestimated.

The changes to capacity due to penstock friction revisions affect:

- capital cost since the turbine sizing (MW) and costing of other components affected by capacity (MW) changed in some cases;

- annual costs that are based on either capital cost or capacity;

- annual and monthly energy, dependable capacity, ELCC and firm energy; and

- Unit Energy Cost (UEC), due to a change in both the costs and annual energy.

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Turbine Sizing and Selection

Multiple turbine case costing: The model was selecting a single large turbine for costing, when in some cases, multiple smaller turbines was planned.

Turbine selection: Adjustments have been made to the head range being considered when selecting the turbine. The turbine selection and costing has now been adjusted.

Where revisions resulted in a change to turbine selection or multiple turbine costing, this affected:

- capital cost;

- annual costs components that are based on capital cost;

- annual and monthly energy, dependable capacity, ELCC and firm energy, due to a change in the turbine shutoff; and

- UEC, due to a change in both the costs and annual energy.

Mobilization

The model was referencing only a portion of the factors that influence mobilization. It was referencing the materials when it should have also been referencing equipment in the estimation of mobilization costs.

The mobilization calculation has been revised to include consideration of both equipment and materials. These revisions affected:

- capital cost;
- annual costs components that are based on capital cost; and
- UEC.

To account for site variations due to regional factors and remoteness (proximity to city centres), costs for construction camps and transportation of people and equipment were added to estimates. Four site categories were used to indicate the remoteness of location. Category A sites were located within a 50 km radius of a major town or city centre (population of 25,000 or more). Category B or C sites were located within 200 to 400 km for a centre, respectively. Category D sites were located anywhere outside a 400 km radius from a city centre. Camp and transportation cost estimates for Site Categories A through D are shown in Table 1 below. Table 2 provides a summary of the additional cost allowance provided for the mobilization and demobilization to and from the site (Note that Table 2 was not presented in the 2010 RoR Update report – March 2011).

Table 1: Total Camp and Transportation Costs ($)

Project Capacity	Location Class A	Location Class B	Location Class C	Location Class D
Less than 1 MW	111,300	222,600	800,830	934,390
1 to 10 MW	222,600	445,200	1,304,330	1,571,450
Greater than 10 MW	333,900	667,800	1,807,830	2,208,510

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Run of River Hydroelectric Resource Assessment for
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Table 2: Additional Site Location Mobilization/Demobilization Allowance

Site Location Class	% of Capital Cost
A	6
B	10
C	18
D	24

Water Survey of Canada Proxy Gauge

In the algorithm that compared an intake's drainage area to the watershed areas of the Water Survey of Canada (WSC) gauges within a hydrologic region, larger intake drainage area value was being used. The algorithm selected a WSC gauge from the correct hydrologic region, but it was not necessarily selecting and weighting based on the gauges KWL set out in the methodology.

The methodology was set out such that within each hydrologic zone, a site was associated to one or two WSC gauges by identifying WSC gauges with the next larger and next smaller drainage area (as compared to the drainage area of the project site). A weighted average based on the ratio of drainage area was used to calculate the energy and power factors for the project site. If the drainage area of the project site was larger than the largest WSC drainage area, then the largest WSC gauge was used. If the drainage area of the site was smaller than the smallest WSC drainage area, the smallest WSC gauge was used. Since the incorrect area for the project site intake was being used, this methodology had not been implemented as planned.

In addition, there was an issue with correct weighting in cases where the project was bigger than the smallest WSC gauge, but smaller than the next gauge in a hydrologic region.

WSC proxy gauge assignment and weighting has been revised. Where revisions resulted in different gauge selections or weightings, this affected:

- annual costs (water rental rate is based on energy);
- annual energy, dependable capacity, ELCC and firm energy;
- monthly energy distribution; and
- UEC, due to a change in annual energy.

Results of Assessment

The study identified over 7,200 potential run-of-river hydroelectric sites in BC. These sites have a revised potential installed capacity of nearly 17,000 MW and annual energy of over 55,000 GWh/yr. KWL estimated the cost for each project, including costs for access and power lines to interconnect to the BC Hydro and Fortis BC grids. Table 3 provides the number of projects, energy, and capacity by price bundle.

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Table 3: Total Run-of-River Hydro Potential in BC

Price Bundle	Number of Projects	Average Annual Energy (GWh/yr)	Annual Firm Energy (GWh/yr)	Installed Capacity (MW)	Effective Load-Carrying Capacity (MW)
80 - 89	4	375	317	118	9
90 - 99	7	1065	870	311	53
100 - 109	7	968	798	247	30
110 - 119	17	1474	1166	406	47
120 - 129	19	1477	1083	404	55
130 - 139	25	1381	1062	407	37
140 - 149	21	1182	916	333	47
150 - 159	24	1276	1050	359	49
160 - 169	25	1242	988	353	42
170 - 179	31	1215	977	362	33
180 - 189	27	996	687	307	38
190 - 199	44	1358	1030	414	58
200 - 250	190	4816	3671	1487	167
250 - 500	902	15187	11503	4727	570
500 - 1000	1159	8276	6079	2654	311
>1000	4780	12892	8778	4017	390
Total	**7,282**	**55,180**	**40,978**	**16,906**	**1,936**

A supply curve for run-of-river hydroelectric potential in BC is presented in Figure 1. Supply curves for the ten (10) major transmission regions in BC are presented in Figure 2.

The attached Map 1 of BC entitled Run-of-River Hydroelectric Potential in British Columbia 2013 Revision shows the location of the nearly 7,300 sites with associated size and estimated unit energy cost range.

Discussion of Results

Given the large number of potential hydropower sites identified, there is considerable potential for future development of run-of-river hydroelectric projects in BC.

As this study involved identifying a complete inventory of potential run-of-river hydroelectric projects, the unit energy costs presented include both the most and least cost-effective projects. The assessment identified 11 projects estimated to have a unit energy cost under $100/MWh with approximately 430 MW of capacity and approximately 1,440 GWh/yr of average annual energy. Table 4 provides a breakdown of the projects with estimated unit energy costs under $100/MWh by major transmission region. Tables 5, 6 & 7 present a breakdown by project size and unit energy cost of total annual energy, capacity, and number of sites respectively.

Table 4: Run-of-River Hydro Potential in BC for Sites under $100/MWh[1]

Transmission Region	Number of Projects	Average Annual Energy (GWh/yr)	Annual Firm Energy (GWh/yr)	Installed Capacity (MW)	Effective Load-Carrying Capacity (MW)
Lower Mainland	7	553	404	164	28
Vancouver Island	2	450	395	119	29
Kelly Nicola	2	438	388	147	5
Total	**11**	**1441**	**1187**	**430**	**62**
Note: The cost is based on a 6% discount rate					

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Table 5: Energy by Project Size[1]

Price Bundle	Annual Energy (GWh/year)			
	< 1 MW	1 to 30 MW	> 30 MW	Total
< $100/MWh	0	364	1,077	1,441
$100 to 149/MWh	0	3,514	2,968	6,482
> $150/MWh	5,348	38,405	3,504	47,257
Total	**5,348**	**42,283**	**7,549**	**55,180**

[1] The cost is based on a 6% discount rate

Table 6: Capacity by Project Size[1]

Price Bundle	Installed Capacity (MW)			
	< 1 MW	1 to 30 MW	> 30 MW	Total
< $100/MWh	0	99	330	429
$100 to 149/MWh	0	1,037	760	1,797
> $150/MWh	1,765	11,950	965	14,680
Total	**1,765**	**13,087**	**2,055**	**16,906**

[1] The cost is based on a 6% discount rate

Table 7: Number of Sites by Project Size[1]

Price Bundle	Number of Projects			
	< 1 MW	1 to 30 MW	> 30 MW	Total
< $100/MWh	0	6	5	11
$100 to 149/MWh	0	74	15	89
> $150/MWh	3,963	3,195	24	7,182
Total	**3,963**	**3,275**	**44**	**7,282**

[1] The cost is based on a 6% discount rate

The unit energy cost (UEC) is greatly influenced by the remoteness of the site, where access and power lines can account for a significant portion of the capital cost. A supply curve with the UECs broken down by site infrastructure and access/transmission costs is presented in Figure 3.

Each site was treated as though it were developed in isolation of other projects. The study is an inventory level assessment and has not individually optimised the size of each plant. As such, the assumptions used to size, optimise and locate potential sites in this study may not provide the most economically viable site configuration or sizing.

More comprehensive site investigation, First Nations consultation, environmental and social assessments, hydrologic data collection and analysis, and concept development is required for developers to proceed with potential project applications prior to licensing, electricity purchase agreements, and construction.

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TECHNICAL MEMORANDUM
Run of River Hydroelectric Resource Assessment for
British Columbia 2013 Revisions
June 20, 2013

KERR WOOD LEIDAL ASSOCIATES LTD.

Prepared by:

Colleen O'Toole, P.Eng.
Project Engineer

Stefan Joyce, P.Eng.
Project Manager

Reviewed by:

Ron Monk, MEng, P.Eng.
Energy & Mining Sector Leader

SFJ/cot/sk

Encl.

This document is a copy of the sealed and signed original retained on file. The content of the electronically transmitted document can be confirmed by referring to the filed original.

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Revision History

Revision #	Date	Status	Revision	Author
0	June 18, 2013	Draft		SFJ/COT
1	June 20, 2013	Final	Comments incorporated	SFJ/COT

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Curve above
$500/MWh not
displayed in order
to show detail at
lower UECs

── UEC at 6% Discount Rate

Figure 1: Supply Curve for Run-of-River Potential in BC at 6% Discount Rate

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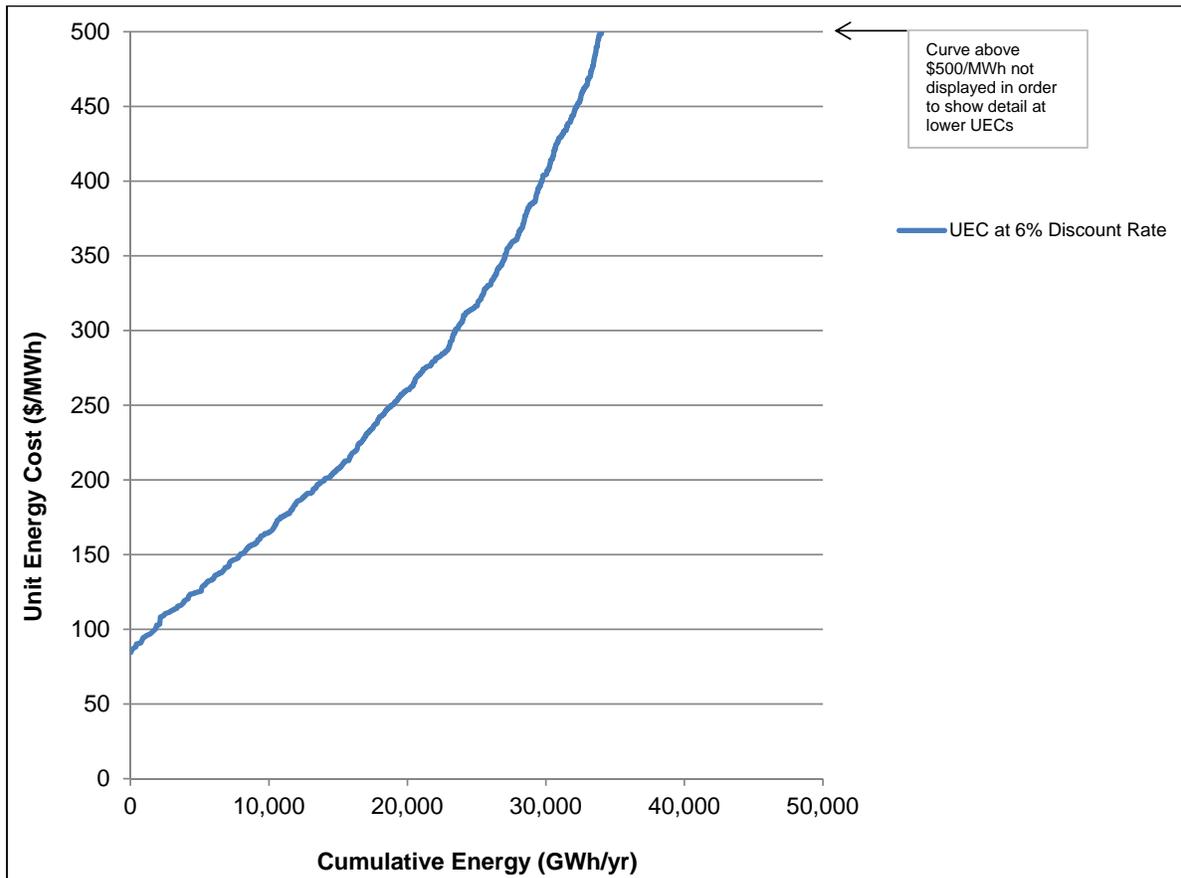
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**Figure 2: Run-of-River Potential Supply Curves by Transmission Region at 6% Discount Rate**

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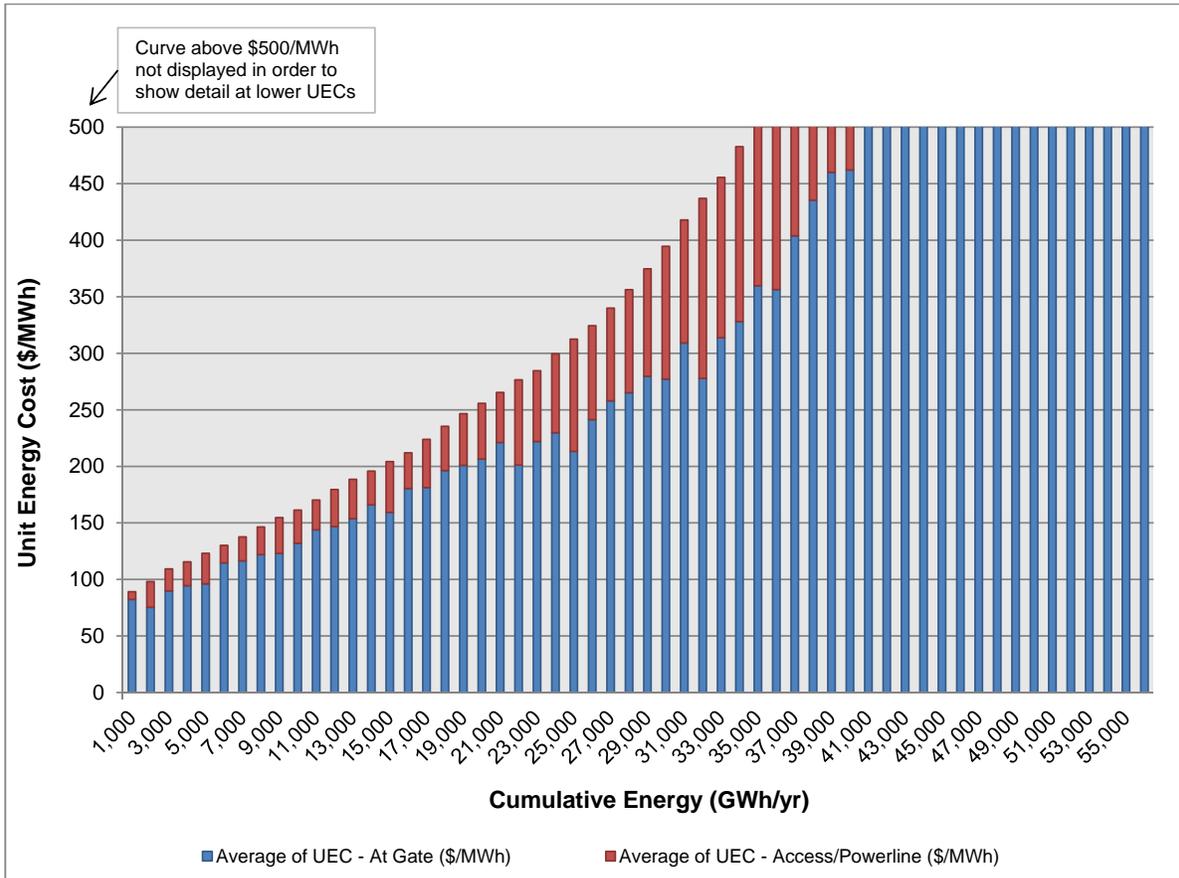
Figure 3: Supply Curve Breakdown for Run-of-River Potential in BC at 6% Discount Rate

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**Figure 4: Average Site Category Cost Breakdown**[1]

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[1] Does not include Annual Costs or IDC

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Site Category A: <50km radius from a major town or city centre
Site Category B: 50 to 1999 km radius from a major town or city centre
Site Category C: 200 to 399 km radius from a major town or city centre
Site Category D: > 400 km radius from a major town o
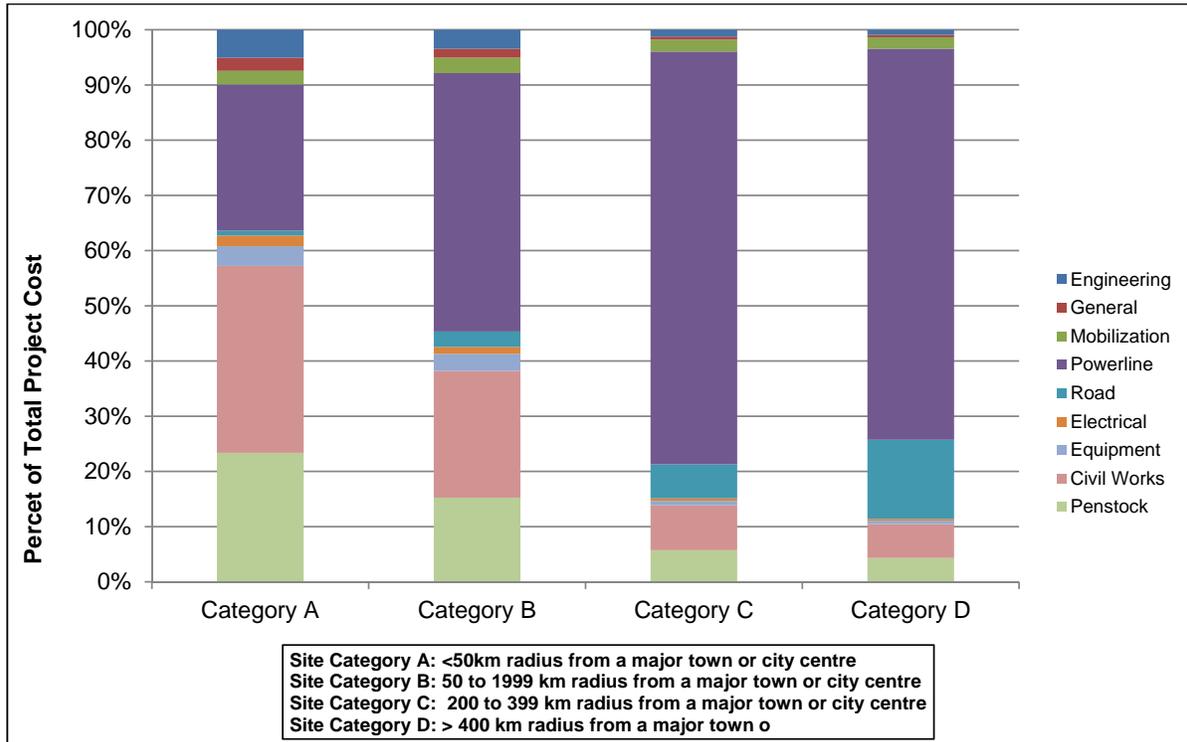
Figure 5: Average Site Category Cost Breakdown as a Per cent of Total[2]

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[2] Does not include Annual Costs or IDC

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**Figure 6: Monthly Energy Profiles – Small Hydro Potential by Transmission Interconnection Region**

Figure 7: Supply Curve with Unit Energy Cost Sensitivity to Discount Rate

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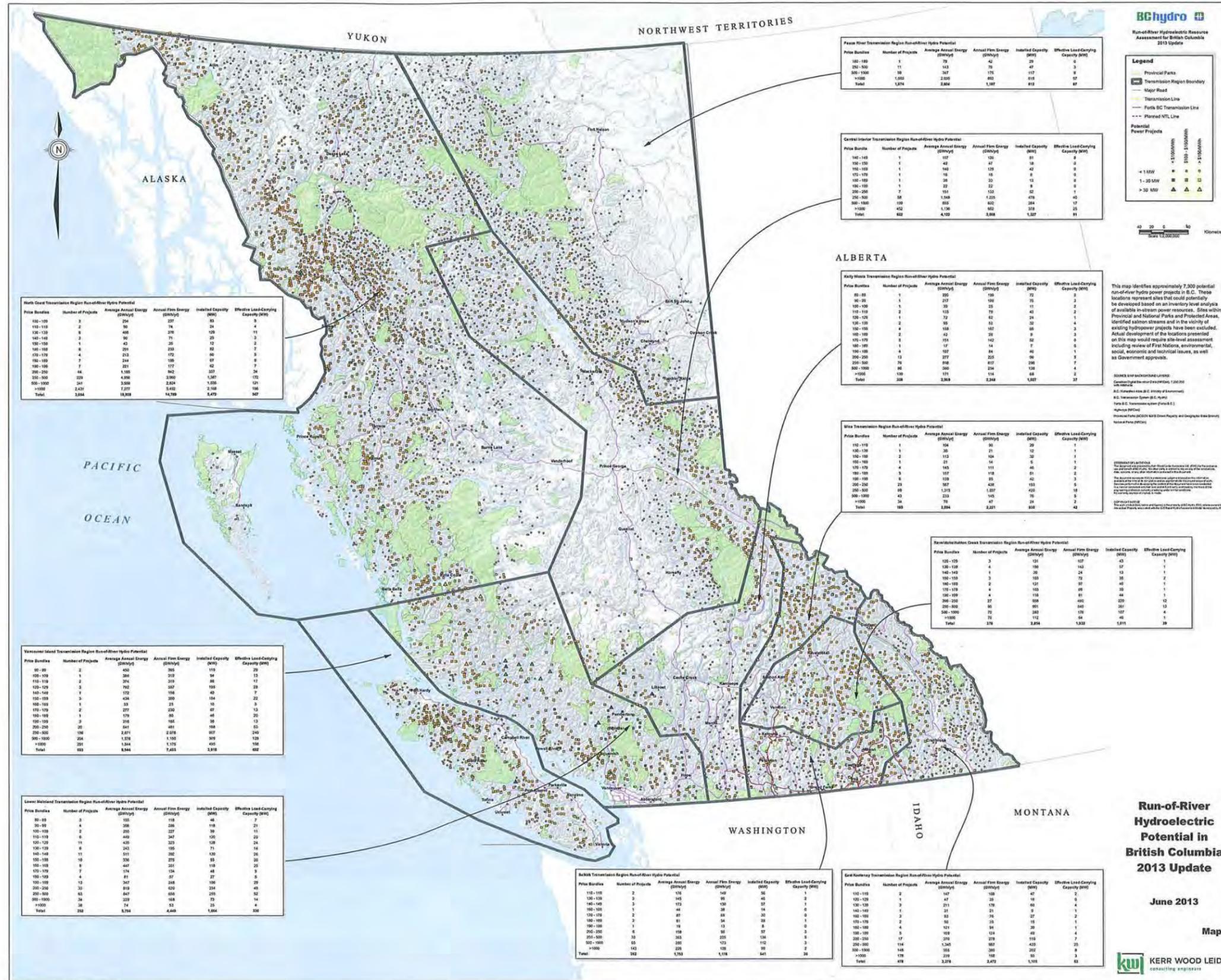
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Run-of-River Hydroelectric Potential in British Columbia 2013 Update

June 2013

Map 1

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Run-of-River Hydroelectric Resource Assessment for British Columbia 2010 Update

Final Report
March 2011

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Run-of-River Hydroelectric Resource Assessment for British Columbia 2010 Update

Final Report
March 2011

KWL File No. 478.103-300

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REVISION HISTORY

Revision #	Date	Status	Revision	Author
A	Dec 17, 2010	Draft	Draft for BC Hydro Review	SFJ
B	March 21, 2011	Final	Final for BC Hydro Review	SFJ

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APPENDICES

Appendix A: Hydrologic Gauge Data
Appendix B: Roads & Power Lines Cost Estimation Using GIS
Appendix C: Hydropower Potential by Transmission Region
(Note: Appendices A, B & C are provided in a separate file on the BC Hydro Integrated Resource Plan website)

Executive Summary

EXECUTIVE SUMMARY

In 2007, BC Hydro commissioned Kerr Wood Leidal Associates Ltd. (KWL) to conduct an inventory of the run-of-river hydroelectric potential in British Columbia. KWL completed the hydroelectric resource assessment using a Geographic Information System (GIS) Hydropower Assessment Model developed by KWL.

This report provides an update on the 2007 study with a revised methodology and improved site optimisation process. Projects were identified for each stream reach through an optimisation routine that determines the project penstock length by assessing the change in gross power divided by the change in length for each potential project location at penstock lengths of 500 m to 5,000 m. The optimised penstock distance routine selects the largest project on a given stream, which is optimised to find the greatest change in gross power over the change in penstock length.

The new methodology results in an estimated project size (capacity & energy) that is expected to provide a closer representation of what a developer might construct for that reach of stream. In general it results in more capacity and energy and often with lower unit electricity costs (UEC). The 2010 methodology provides a new inventory that is more representative of British Columbia's run-of-river hydroelectric potential.

DISCUSSION OF UPDATES

The study identified over 7,200 potential run-of-river hydroelectric sites in BC. These sites have a potential installed capacity of over 17,400 MW and annual energy of nearly 63,000 GWh/yr. KWL estimated the cost for each project, including costs for access and power lines to interconnect to the BC Hydro and Fortis BC grids. Table E-1 provides the number of projects, energy, and capacity by price bundle. It also includes an estimation of the impacted area and job creation opportunities.

Table E-1: Run-of-River Hydro Potential in BC

Price Bundle	Number of Projects	Average Annual Energy (GWh/yr)	Annual Firm Energy (GWh/yr)	Installed Capacity (MW)	Dependable Generating Capacity (MW)
65 - 69	1	89	66	20	2
70 - 74	3	212	172	53	1
75 - 79	3	664	503	173	6
80 - 84	5	930	698	222	17
85 - 89	3	177	142	45	0
90 - 94	7	698	531	167	12
95 - 99	9	684	556	179	8
100 - 109	30	2,135	1,708	543	34
110 - 119	46	3,512	2,710	847	61
120 - 129	22	1,251	1,045	330	8
130 - 139	36	1,706	1,379	443	18
140 - 149	44	1,920	1,549	486	27
150 - 159	39	1,971	1,584	492	25
160 - 169	37	1,427	1,189	376	8
170 - 179	47	1,758	1,449	473	15
180 - 189	40	1,401	1,141	363	14
190 - 199	51	1,330	1,098	357	5
200 - 299	452	10,320	8,321	2,820	63
300 - 399	399	6,149	4,978	1,732	31
400 - 499	365	4,204	3,331	1,193	16
500 - 599	277	2,163	1,733	637	9
600 - 699	241	2,015	1,575	570	8
700 - 799	230	1,621	1,255	472	5
800 - 899	193	1,578	1,229	445	5
900 - 999	177	1,124	875	322	3
1000 +	4,525	11,816	9,075	3,645	16
Total	**7,282**	**62,858**	**49,890**	**17,404**	**420**

A supply curve for run-of-river hydroelectric potential in BC is presented in Figure E-1. Supply curves for the ten (10) major transmission regions in BC are presented in Figure E-2.

The attached Map E-1[1] of BC entitled *Run-of-River Hydroelectric Potential in British Columbia 2010 Update* shows the location of the nearly 7,300 sites with associated size and estimated unit energy cost range.

Methodology

The GIS Rapid Hydropower Assessment Model (RHAM) developed by KWL estimated in-stream power using topographic and hydrologic GIS data. The resulting output was over 10 million data points representing potential power plant points-of-diversion complete with flow,

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[1] Note: Map E-1 is provided in a separate file on the BC Hydro Integrated Resource Plan website.

head and power estimations. This data was then screened for physical parameters suitable for run-of-river power development, and areas considered undevelopable such as legally protected areas, salmon streams and existing project locations. The aforementioned 7,300 projects were identified using an optimisation process based on power output relative to the infrastructure required.

Regional hydrology analysis was carried out to develop an estimate of energy production. This exercise involved statistical analysis of Water Survey of Canada (WSC) hydrologic data, and used GIS capabilities to distribute the resulting statistics to the proposed project locations. Annual energy production, 'firm energy' and 'dependable capacity', were estimated based on flow duration curves. Minimum flow releases for fish were assumed to be 15% of mean annual discharge.

Upon identifying potential project sites, the physical characteristics and project location were used to estimate an approximate cost to develop each project. This was accomplished through the development and utilization of cost curves for project components (e.g., turbine, civil works) that were based on actual projects developed in British Columbia. Each site had access and power line costs estimated as if it were constructed in isolation of other projects.

Unit energy cost (UEC) was determined based on available estimated energy production and annual capital and operating costs. Annual capital costs were calculated assuming a 40-year amortization period, with a real discount rate of 6%. A discount rate of 8% was also considered for comparison in a sensitivity analysis. Other annual costs included property taxes, water rental, and plant operations and maintenance.

The planning level unit energy costs may not reflect what an independent power producer may offer to sell electricity to BC Hydro due to factors such as:

- Site-specific considerations;
- Cost of capital;
- Contract terms;
- Taxation; and
- Other factors.

DISCUSSION OF RESULTS

Given the large number of potential hydropower sites identified, there is considerable potential for future development of run-of-river hydroelectric projects in BC.

As this study involved identifying a complete inventory of potential run-of-river hydroelectric projects, the unit energy costs presented include both the most and least cost-effective projects. The assessment identified 31 projects estimated to have a unit energy cost under $100/MWh with approximately 900 MW of capacity and approximately 3,500 GWh/yr of average annual energy. Table E-2 below provides a breakdown of the projects with estimated unit energy costs under $100/MWh by major transmission region.

Table E-2: Run-of-River Hydro Potential in BC for Sites under $100/MWh

Transmission Region	Number of Projects	Average Annual Energy (GWh/yr)	Annual Firm Energy (GWh/yr)	Installed Capacity (MW)	Dependable Generating Capacity (MW)
East Kootenay	3	255	236	76	0
Kelly Nicola	6	873	658	228	8
Lower Mainland	17	1,328	1,025	323	16
North Coast	2	153	124	40	0
Revelstoke/Ashton Creek	1	67	51	17	1
Vancouver Island	2	778	573	175	21
Total	**31**	**3,455**	**2,668**	**858**	**47**

The unit energy cost (UEC) is greatly influenced by the remoteness of the site, where access and power lines can account for a significant portion of the capital cost. A supply curve with the UECs broken down by site infrastructure and access/transmission costs is presented in Figure E-3.

Each site was treated as though it were developed in isolation of other projects. The study is an inventory level assessment and has not individually optimised the size of each plant. As such, the assumptions used to size, optimise and locate potential sites in this study may not provide the most economically viable site configuration or sizing.

More comprehensive site investigation, First Nations consultation, environmental and social assessments, hydrologic data collection and analysis, and concept development is required for developers to proceed with potential project applications prior to licensing, electricity purchase agreements, and construction.

RUN-OF-RIVER HYDROELECTRIC RESOURCE ASSESSMENT
FOR BRITISH COLUMBIA 2010 UPDATE
FINAL REPORT - MARCH 2011

BC HYDRO & POWER AUTHORITY

Supply Curve for Run-of-River Potential in BC at 6% Discount Rate

Figure E-1

RUN-OF-RIVER HYDROELECTRIC RESOURCE ASSESSMENT
FOR BRITISH COLUMBIA 2010 UPDATE
FINAL REPORT - MARCH 2011

BC HYDRO & POWER AUTHORITY

Supply Curves by Transmission Region at 6% Discount Rate

Curves above $500/MWh not displayed in order to show detail at lower UECs

- Central Interior
- East Kootenay
- Kelly Nicola
- Lower Mainland
- Mica
- North Coast
- Peace River
- Revelstoke / Ashton Creek
- Selkirk
- Vancouver Island

Cumulative Energy (GWh/yr)

Unit Energy Cost ($/MWh)

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Figure E-2

BC HYDRO & POWER AUTHORITY

Supply Curve Breakdown for Run-of-River Potential in BC at 6% Discount Rate

Curves above $500/MWh not displayed in order to show detail at lower UECs

- ☐ Average of UEC - Access/Powerline ($/MWh)
- ■ Average of UEC - At Gate ($/MWh)

Cumulative Energy (GWh/yr)

Unit Energy Cost ($/MWh)

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Figure E-3

Section 1

Introduction

1. INTRODUCTION

In 2007, BC Hydro commissioned Kerr Wood Leidal Associates Ltd. (KWL) to conduct an inventory of run-of-river hydroelectric potential in British Columbia. In August 2010, BC Hydro engaged KWL to conduct an update to the 2007 study with a revised methodology, updated costing, and improved site optimisation process.

Figure 1-1 shows BC Hydro's transmission and distribution system. Connection to the existing integrated power system was included in the assessment.

The geography and precipitation of British Columbia provides many opportunities for hydroelectric development. While previous studies of run-of-river hydroelectric potential in BC have identified many potential hydroelectric projects in the study area, these past studies focused on areas near existing power lines and on small run-of-river projects. This study includes a complete assessment of all potential run-of-river power development in the province.

This study and the 2007 KWL Study were completed using a Geographical Information System (GIS) Rapid Hydro Assessment Model (RHAM) developed by KWL, which enabled a more comprehensive study of the hydroelectric potential in BC.

1.1 OBJECTIVES AND SCOPE

The primary project objectives of the update to the 2007 GIS based inventory of run-of-river hydroelectric potential for BC include:

- An update to the areas and reaches of streams excluded from the analysis that are considered undevelopable such as legally protected areas, reaches of streams that are used by salmon, glacier areas, and existing and committed project locations.

- Development of a new run-of-river hydropower inventory for BC using a revised/improved optimisation methodology developed by KWL, since 2007, that more closely compares with hydroelectric projects that are presently being proposed and developed in BC.

- Develop inventory-level cost estimates for run-of-river hydro by transmission region based on updated cost data in January 1, 2011 dollars.

1.2 FIRST NATIONS AND STAKEHOLDER INPUT

KWL gratefully acknowledges the input of First Nations and stakeholders from meetings held by BC Hydro on September 14 and 20, 2010.

Figure 1-1

Section 2

Power and Energy Analysis

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2.   POWER AND ENERGY ANALYSIS

KWL estimated the run-of-river hydroelectric potential for the province of British Columbia. This was made possible through improved GIS technology and data, and the recent assessment tools developed by KWL.

Run-of-river facilities use the unregulated flow of rivers or creeks to generate power. This type of hydroelectric project can be constructed with a small weir, dam or low diversion structure (intake or point of diversion) to direct a portion of the stream flow into a penstock that conveys flow to a powerhouse. A turbine and generator in the powerhouse convert the potential energy into electricity, and the diverted water is returned to the stream via a tailrace channel.

2.1   GIS RAPID HYDRO ASSESSMENT MODEL OVERVIEW

KWL developed a GIS-based tool referred to as the Rapid Hydro Assessment Model or RHAM for estimating run-of-river power potential. With improvements in GIS technology, as well as increased availability of high-quality topographic and hydrologic data, it is possible to assess power potential on a widespread basis, while maintaining a relatively high level of detail.

The tool developed by KWL is capable of determining three key parameters for power generation:

- Stream Flow and Distribution: used to select a design flow for sizing potential power projects;

- Static Head: the vertical distance between the point-of-diversion and potential powerhouse locations; and

- Power: product of head, flow and fluid density, not including frictional or generation losses.

Once these parameters were estimated, project components were sized, frictional losses were estimated and the resulting 'net' power was calculated. This information was then used to estimate available hydroelectric capacity and approximate capital costs. In addition to estimating hydropower potential, GIS capabilities have been used in preparing estimates of capital costs for items such as access roads and power lines (see Section 3: Cost and Economic Analysis).

Regional hydrology analysis was carried out to develop an estimate of energy production. This involved statistical analysis of Water Survey of Canada (WSC) hydrologic data, and use of GIS capabilities to distribute the resulting statistics to the potential project locations. Annual energy production, 'firm energy' and 'dependable capacity', were estimated based on flow duration curves.

The model was developed using ArcGIS 9.2 (and later ArcGIS 10) software with the Spatial Analyst extension, which is available from ESRI Canada. This software is widely recognized as the industry standard for engineering GIS applications.

2.2 GEOGRAPHIC INFORMATION SYSTEM TERMINOLOGY

This document refers to GIS-specific terminology. Some of the terms and abbreviations commonly used in this report are as follows:

Table 2-1: GIS Terminology

GIS	Geographic Information Systems – a tool that merges databases with spatial references, and provides tools for mapping and analysis.
DEM	Digital Elevation Model – a continuous representation of the Earth's surface using spot elevations, uniform grids of cells, or triangular networks.
Vector	A data model for discrete objects; can represent entities as points, lines or polygons.
Raster	A data model for continuous data; uses uniform grids of cells with a single attribute to form a 'surface'.
Geoprocessing	Automated tools for analyzing relationships between or within datasets.
NTS	National Topographic System – a gridded reference system used by Provincial and Federal governments for mapping products.

2.3 GEOGRAPHIC INFORMATION SYSTEM DATA SOURCES

The primary data sources used in this assessment were acquired through public data warehouses available through the Internet. These websites include the Land Resource Data Warehouse (lrdw.ca) operated by the Integrated Land Management Bureau (Province of BC), Geobase (geobase.ca) and Geogratis (geogratis.ca), operated by Natural Resources Canada (NRCan). BC Hydro & Fortis BC Data transmission and distribution system data were also utilized on this project. Table 2-2 describes the publicly available datasets used in the assessment.

Table 2-2: Data Sources for Hydropower Assessment

Dataset	Data Type/ Accuracy	Source/Author	Description
Canadian Digital Elevation Data (CDED)	DEM/1:250K resolution	Geobase	Continuous representation of surface relief.
Normal Annual Runoff Isolines	Vector/500 mm contour interval	LRDW/Obedkoff et al.	Normal annual depth of runoff.
BC Watershed Atlas	Vector/based on 1:20K mapping	LRDW/Water Management Branch	Topographic reference for mapped hydrologic features.
HYDAT Data 2005	Tabular	Water Survey Canada (WSC)	Daily flow data recorded and archived by WSC for all of Canada.
Hydrologic Zones	Vector/1:2M	LRDW/Obedkoff et al.	29 Regions of hydrologically similar Areas in BC.

Canadian Digital Elevation Data (CDED)

The CDED DEM is supplied in tiles based on the NTS 1:250K grid system. Each tile is approximately 100 km x 100 km in size, with a 'pixel' size of approximately 93 m. The DEM is corrected for hydrology, which means that elevations have been adjusted such that cells occurring along known hydrologic features 'flow' in the downstream direction. Figure 2-1 shows a topographic map of BC using the CDED DEM.

Normal Annual Runoff Isolines

The Normal Annual Runoff Isolines data were developed as a part of the 1998 British Columbia Streamflow Inventory. The isolines were interpolated to a continuous surface and combined with the DEM for estimating streamflows. Figure 2-2 shows the normal annual runoff for BC.

BC Watershed Atlas

The BC Watershed Atlas has been in existence for a number of years, and is widely used as a topographic reference for named and unnamed hydrologic features. The key components of this dataset are mapped streamlines, bodies of water and watershed boundaries. This dataset provides topographic names for associating the power model results to known features.

Streamflow on the far western portion of Vancouver Island and the Haida Gwaii may be slightly underestimated due to a boundary effect in the runoff surface where no isolines were available. This may affect a small number of sites as a large portion of this area is also park and not considered developable.

Hydrologic Data

Water Survey of Canada (WSC) records and archives historic hydrometric flow data for Canada. Daily WSC flow data, geographic locations, and gauge characteristics are available online and can be downloaded (HYDAT 2005). The historical daily data to 2005 for all the WSC gauges in BC were used for the purposes of this study.

Hydrologic Zones

A hydrologic zone is defined as an area where, theoretically, hydrologic characteristics are similar. Data collected in each hydrologic zone can therefore be extrapolated to estimate characteristics at ungauged sites with a reasonable degree of accuracy. For this project, hydrologic zones are used to estimate regional streamflow characteristics.

Hydrologic zones in BC were defined by Coulson and Obedkoff in the 1998 British Columbia Streamflow Inventory. Subsequent work by Obedkoff between 1998 and 2003 updated the information in each region, and increased the total hydrologic zones to 29. Figure 2-3 shows these hydrologic zones and their constituent WSC hydrometric stations.

2.4 POTENTIAL HYDROPOWER PROJECT IDENTIFICATION METHODOLOGY

This section describes the steps involved in estimating available in-stream hydropower potential and in identifying potential run-of-river hydropower project locations. Given the wide coverage and coarse source data, the results are most appropriate for identifying approximate locations that could support economically viable projects, and comparing relative suitability between proposed project locations. Although a planning level optimisation process has been applied in this study, for development purposes optimal locations within a given watershed should be confirmed as part of a more detailed watershed-specific assessment. The methodology presented in this study is intended to identify streams that warrant further investigation.

Several steps are involved in assessing hydropower potential. These include:

- Estimation of in-stream power;
- General screening to identify technically feasible project locations;
- An optimisation routine for identifying suitable projects within a watershed;
- Sizing of project components such as penstock, powerhouse and power lines;
- Estimation of net power; and
- Estimation of energy production.

Each of these steps are described below.

Figure 2-4 describes the model conceptually.

GROSS HYDROPOWER POTENTIAL

Two parameters flow (Q) and head (H), are required for determining in-stream power potential. In-stream power is the product of head, flow and fluid weight, as described by the following equation:

$$P_{gross} = \gamma_w Q H_s$$

where,

P_{gross} = in-stream power (kW)

γ_w = 9.81 kN/m^3 (constant)

Q = flow (m^3/s)

H_s = static head from intake to powerhouse (m)

Flow

Mean annual discharge (MAD) at any given site can be estimated using GIS tools as an initial estimation for the average flow available at a site (a design flow factor was later applied). These GIS tools were applied to the DEM to calculate the area upstream of each cell within a raster. The resulting area accumulation raster was then combined with the runoff surface to estimate mean annual runoff:

Area Accumulation x Mean Annual Runoff Depth = Mean Annual Discharge

Mean annual discharges were validated against hydrological statistics from Water Survey of Canada stream flow gauges (see Section 2.5 – Quality Control).

The above procedure identifies stream locations implicitly, and independently of any existing stream mapping. For this reason, streamlines generated by the model do not always align with mapped streams.

Head

Head is estimated by using spatial statistics functions that are included in ArcGIS. These functions were configured to perform a search around a given point and return the minimum elevation, which was assigned back to the search location. The search was conducted radially in 500 m increments, from 500 m to 5,000 m.

The raw topographic head dataset from 2007 was utilized for the 2010 inventory. Some run-of-river hydroelectric projects are now being designed and constructed with penstocks in excess of 5,000 m long. Future run-of-river inventory updates should consider the application of penstock lengths that are longer than 5,000 m.

To prevent the search from identifying a minimum elevation in a neighbouring watershed, an algorithm was developed. This was completed using the smallest watershed division, as defined in the BC Watershed Atlas, and by combining a unique identifier for each watershed with the data returned from the statistical function.

Static head was estimated by subtracting the minimum elevation returned by the search algorithm from the elevation of the current DEM cell for each iteration. The end result was a series of rasters of potential static head at various search distances. The search distance then formed the basis for estimating the penstock length at a given location.

In-Stream Power Potential

As shown above in the in-stream power equation, head was multiplied by flow and fluid weight to yield in-stream power. ArcGIS was used to multiply the head and flow rasters, thereby producing a raster of in-stream power. The power rasters were then converted to vector datasets of points representing potential power project locations. The vector dataset was able to store all of the information at each location, including head, flow and instream power. This resulted in the production of a dataset containing approximately 10 million points.

Because in-stream power potential was based on MAD, the in-stream power output represents the average power potential available within a typical year. Project locations specified in this analysis represent the point-of-diversion.

SITE SCREENING

Boundary Conditions

Given the large size of the initial power model output, the next step was to identify sites that are technically feasible for development. Table 2-3 describes the physical characteristics used as screening criteria.

Table 2-3: Physical Boundary Conditions

Parameter	Valid Range
Slope	> 4%
Mean Annual Discharge	$0.1 - 200 \ m^3/s$
Static Head	$30 - 1,000 \ m$
In-Stream Power	> 100 kW

In general, the minimum flow, head and power conditions represent practical limits to generating grid connected small hydropower from an economic standpoint. The maximum flow condition essentially establishes a limit for medium-sized hydro facilities. The maximum head condition represents a maximum practicable pressure rating for penstocks and generating units.

Exclusion Areas

In some areas, it was assumed that a power project could not be built. These areas were masked in GIS and intersected with the power model output to extract only those points that were considered suitable locations for developing power. Table 2-4 summarizes the type of features included in the mask, the source of the data, and the process used to create the mask.

Table 2-4: Undevelopable Areas

Feature	Source	Process
Salmon Species Presence	Province of British Columbia, GeoBC, LRDW (FISS)	No projects within 100 m of exclusion area
Biodiversity Areas	Province of British Columbia, GeoBC, ILMB	No projects within 100 m of exclusion area
Wildlife Management Areas *areas for which administration and control has been transferred to the Ministry of Environment (MoE) via the Land Act due to the significance of their wildlife/fish values and designated as Wildlife Management Areas under the Wildlife Act*	Province of British Columbia, GeoBC, LRDW	No projects within 100 m of exclusion area
Conservancy Areas *conservancy areas designated under the Park Act or by the Protected Areas of British Columbia Act, whose management and development is constrained by the Park Act*	Province of British Columbia, GeoBC, LRDW	No projects within 100 m of exclusion area
National Parks	Province of British Columbia, GeoBC, LRDW	No projects within 100 m of exclusion area
Energy Purchase Agreements (EPAs) / Existing BC Hydro Facilities	BC Hydro, MOE Water Licenses	No projects within 500 m of existing projects
Legally Protected Areas *Ecological Reserves, Protected Areas, Provincial Parks, Recreation Areas*	Province of British Columbia, GeoBC, LRDW	No projects within 100 m of exclusion area
Canadian Forces Bases	CFB Esquimalt (Navy) CFB Comox (Air Force)	No projects within 100 m of exclusion area
Migratory Bird Sanctuaries	Environment Canada	No projects within 100 m of exclusion area
Glaciers	Province of British Columbia, GeoBC, CWB	No projects within 100 m of exclusion area

Provincial and National Parks and protected areas are not suitable for construction of power projects, access roads or transmission lines. Stream reaches containing salmon resources are unlikely to be approved for water licenses without significant mitigation and protection measures, and have also been excluded.

In areas where projects or Electricity Purchase Agreements (EPAs) exist, no new projects in the watershed within a distance of 500 m were permitted.

POWER PROJECT IDENTIFICATION

After screening out locations in undevelopable areas, a large quantity of potentially developable sites remained. An optimisation routine was developed to create a manageable inventory of projects that could be developed independently, and without encroachment upon each other. After identifying potentially optimal locations, project components were sized and net power estimated.

The 2010 update included the application of new optimisation methodology developed by KWL that more closely compares with hydroelectric projects that are presently being proposed and developed in BC.

Optimisation Routine & Design Flow Factor

The site optimisation and selection methodology of the 2007 KWL study found the greatest power per unit length of penstock. This effectively finds the steepest drop for a given reach of stream. As an example, if there are two steep drops nearby, the larger of the two will generally be selected. In 2007 the mean annual discharge (MAD) was used as the design flow.

The methodology from the 2007 work was a reasonable indicator for identifying potential sites, but often developers design a larger project to optimise the cost effectiveness of the project and extract as much capacity and energy as they can from a location since many capital costs are less sensitive to the size of the project and are a large portion of the total cost. This generally results in a project that extends beyond the steepest drop in a reach of the stream and a design flow that is greater than the MAD. The new optimisation and site selection methodology used for the 2010 run-of-river update was designed to align more closely with what a developer might construct.

Both the 2007 and 2010 methodology consider the steepest section of the stream, however the 2010 methodology generally selects larger projects with the steepest section encompassed by the larger potential project

The 2010 optimisation results in both a change to the project layout size (length of diverted stream and head) and a higher design flow. It selects the largest project on a given stream which is optimised to find the greatest change in gross power over the change in penstock length. This effectively finds the steepest drop of a stream reach and also includes nearby steep channel sections and nearby steep drops within the total length of the penstock. In addition to this, a larger design flow of 150% of MAD was used.

Conflicts between potential projects were resolved by creating buffers around projects using the optimised penstock distance. The smaller of the conflicting projects was removed from the project inventory.

After completing the optimisation process, a total of 7,282 potential sites were identified.

Penstock Design Criteria

To estimate costs and potential power generation, the size and length of the water conduit was determined as per the following criteria:

- Penstock Slope: static head over search distance, with a maximum slope of 75%;

- Penstock Length: length obtained from optimisation routine;

- Penstock Material: steel, either (250 psi) or (600 psi) pressure rating based on static head, Hazen Williams C-factor of 120; and

- Penstock Sizing: allow maximum friction loss through conduit of 20% of static head using Hazen-Williams relationship or as required to maintain a minimum overall power efficiency of 75%, with a 10% length allowance for adjustments to alignment.

The maximum nominal penstock diameter assumed was 5 m (198 in.). Inside pipe diameters were used to estimate friction losses. In some cases, parallel conduits have been specified where potential design flows exceed the capacity of the largest penstock diameter.

Net Power Calculation

After sizing the penstock, the net available power was calculated according to the following equation:

$$P_{net} = \gamma_w \, F_{Design} Q_{MAD}(H_s - H_f)\eta$$

where:
P_{net} = design plant capacity (kW)
γ_w = 9.81 kN/m^3 (constant)
F_{Design}= Design Flow Factor (1.5 used for this study)
Q_{MAD} = mean annual discharge (m^3/s)
H_s = static head from intake to powerhouse (m)
H_f = frictional headloss (m)
η = power plant efficiency at design flow, assume 0.85

After allowing for frictional and power plant losses and including the 1.5 times MAD design flow factor, the design plant capacities of the identified projects ranged from 0.1 MW to 98 MW, with the output power efficiency ranging from 75% to 84% of the in-stream power.

SITE CAPACITY, DEPENDABLE CAPACITY AND FIRM ENERGY

The variability or distribution of flow, and hence power generation, was estimated from historical daily flow data. With this information, the annual energy production for a normal year (annual energy), annual energy production for a low flow year (firm energy), and the power that can be relied upon during high demand periods (dependable capacity) can be estimated for potential project sites.

Some definitions referred to in this section are provided below:

- Annual Energy: the total quantity of energy that could be generated annually on average for the entire period of hydrologic record;

- Firm Energy: the total quantity of energy that could be generated during the lowest flow water year (October to September) on record;

- Installed Capacity: the maximum power that can be generated at the site, equal to the design plant capacity;

- Dependable Capacity: the power that could be generated 85% of the time in January and December peak demand period; and

- Minimum Flow Releases for Fish: these were assumed to be 15% of the MAD.

Assembling WSC Gauges into a Regional Stream Flow Database

For the purposes of this assessment, Water Survey of Canada (WSC) records were assumed to provide reasonable flow distribution characteristics for potential project sites within the same hydrologic zone. The available WSC records were compiled and subdivided into the 29 hydrologic zones identified by Obedkoff.

Once compiled, WSC gauge records for BC were screened as follows:

- Regulated hydrometric stations (i.e., stations downstream of dams/reservoirs) were removed as they do not represent natural flow conditions and would not be representative for a run-of-river site;

- Years with greater than one month of missing data were excluded from each hydrometric record to avoid biasing annual and seasonal statistics; and

- Hydrometric records with less than 10 years of data (after partial years removed) were excluded.

Following the screening process, a list of WSC gauges was compiled to assess the availability of screened gauge data for each hydrologic zone. Some hydrologic zones were found to have limited WSC data. In Hydrologic Zone 5, a discontinued gauge with only 9 years of data was included to improve representation of small drainage areas. A summary table for the gauges by hydrologic zone is provided in Appendix A.

The geographical distribution of WSC gauges in some zones is not ideal. The gauge density tends to be lower in remote or sparsely populated areas, particularly for gauges with small drainage areas. For example, in Hydrologic Zone 27 the majority of gauges are concentrated in the southern portion, while most of the gauges in Hydrologic Zone 10 are in the eastern portion.

Although hydrologic zones are defined to be relatively homogeneous, some variability across each zone is still expected. Estimates of flow distribution for potential hydro sites may therefore be biased toward the flow distribution characteristics of sub-regions with a higher density of gauges. The strength of this effect will depend on the degree of hydrologic variability within the defined hydrologic zone.

Estimating Power and Energy Factors for WSC Gauges

Energy factors were calculated for each WSC gauge as follows:

- The *Annual Energy Capacity Factor* was calculated by preparing a flow duration curve with daily data (less fisheries flows) for the data set. An Annual Energy Capacity Factor was calculated based on this flow duration curve and represents the ratio of the annual energy production to the energy if a site were operating at design capacity at all times.

- The *Monthly Energy Capacity Factors* were calculated in the same manner as the annual energy capacity factors, but with the data sorted by month.

- The *Firm Energy Capacity Factor* was calculated by preparing a flow duration curve using the daily data (less Fisheries Flows) for the year with the lowest annual runoff on record for a water year starting October 1. A Firm Energy Capacity Factor was calculated based on this flow duration curve and represents the ratio of the Firm Energy production to the energy if a site were operating at design capacity at all times.

- The *Dependable Capacity Factor* was calculated based on the power that could be produced at the flow that is exceeded 85% of the time in January and December peak demand period over the entire set of daily data. Fisheries flows were subtracted prior to the power calculation.

- The *Effective Load Carrying Capability (ELCC)* was calculated as the capacity (MW) based on 60% of the average energy of December & January divided by the number of hours in the period.

The impact of reduced turbine efficiency at low flows on energy factors was accounted for by assuming no operation at less than a set turbine shut off flow which depended on the turbine type and number of turbines (see Section 3.2). For sites with low flows during the months of December and January, this often resulted in a Dependable Capacity Factor of zero.

A table with factors for the WSC gauges by hydrologic zone is provided in Appendix A.

Estimating Power and Energy Factors for Potential Hydropower Sites

Potential project sites were grouped into the 29 hydrologic zones identified by Obedkoff. Power and energy factors (Annual Energy, Firm Energy, and Dependable Capacity) for each potential project were estimated from WSC records for gauges similar in drainage area to that project site. Each site was associated with at least one WSC gauge in the same hydrologic zone. This was done by identifying WSC gauges with the next larger and next smaller drainage area (as compared to the drainage area of the project site). A weighted average based on the ratio of drainage area was used to calculate the energy and power factors for the project site.

If the drainage area of the project site was larger than the largest WSC drainage area, then the largest WSC gauge was used. If the drainage area of the site was smaller than the smallest WSC drainage area, the smallest WSC gauge was used.

Flow Distribution and Seasonal Variability

Energy production and dependable capacity for a run-of-river hydropower project are a function of the variability and distribution of the flow. The factors that affect the distribution and timing of the runoff for a watershed are complex.

Watershed storage and attenuation can affect variability and distribution of the flow. Watershed characteristics that provide runoff storage and attenuation can include (but are not limited to) lakes and groundwater storage, large drainage area, slope and ground cover. Snow and glaciers also strongly affect the timing of runoff. It is difficult to fully account for storage and attenuation given the limits of the historical WSC records and the inventory-level nature of this resource assessment. Nonetheless, some of the potential variability in watershed storage and attenuation is reflected by using WSC gauges with similar drainage areas to predict stream flow variability for each project site.

Regional factors can also affect variability and distribution of the flow. The amount and form of precipitation at a given site may be strongly influenced by physical factors such as latitude, distance from the coast, and dominant regional climate processes such as large-scale orographic (i.e., elevation of land) uplift. As described above, the annual runoff isolines were used to develop site-specific estimates of mean annual discharge. Flow characteristics were assigned based on WSC gauges located in the same hydrologic zone. This process incorporates a significant amount of the larger-scale regional variability into the results.

In general, using area and hydrologic zone to attribute flow distribution provides a reasonable approximation but does not provide a complete picture of site-specific flow distribution and seasonal variability. Individual sites require a more in-depth regional analysis as well as local in-stream hydrometric data collection as part of site feasibility assessment and development.

2.5   QUALITY CONTROL

MEAN ANNUAL DISCHARGE VALIDATION

The mean annual discharge estimated by the model at WSC gauge locations was compared to the observed mean annual discharge to assess the validity of the model.

The values from the model were directly compared to the values from the gauge and a linear trend line was developed. It was found that on average the model estimates were 2% less than the observed mean annual discharge. The trend line had a R^2 value of 0.97 which is a very good fit.

INTER-DRAINAGE FLOW

Once the model produced an initial estimate of in-stream power potential throughout BC, a quality control measure was taken to check that no major inter-drainage flow existed. Flows across drainage boundaries (inter-drainage flow) generally occurred in areas of flat terrain, especially in areas with many interconnected lakes, which results in the modelling process not being able to determine which direction the water flows.

These areas were identified and corrected by changing the DEM to improve drainage definition within the modelling process. The DEM was changed in such a way that no excess power would be estimated.

TRANS-BOUNDARY FLOW

In the case of watersheds that have flows that originate outside the provincial boundaries, flow contribution from outside of British Columbia, was not accounted for. This does not affect watersheds that originate in British Columbia and subsequently flow outside the provincial boundary. This was considered acceptable for this inventory level as this represents a relatively very small portion of the Province's watersheds by area and it would tend to underestimate the flow in those locations and result in a conservative power estimate.

Topographic Surface of British Columbia — Figure 2-1

Normal Annual Runoff Isolines and Surface

Figure 2-2

Figure 2-3
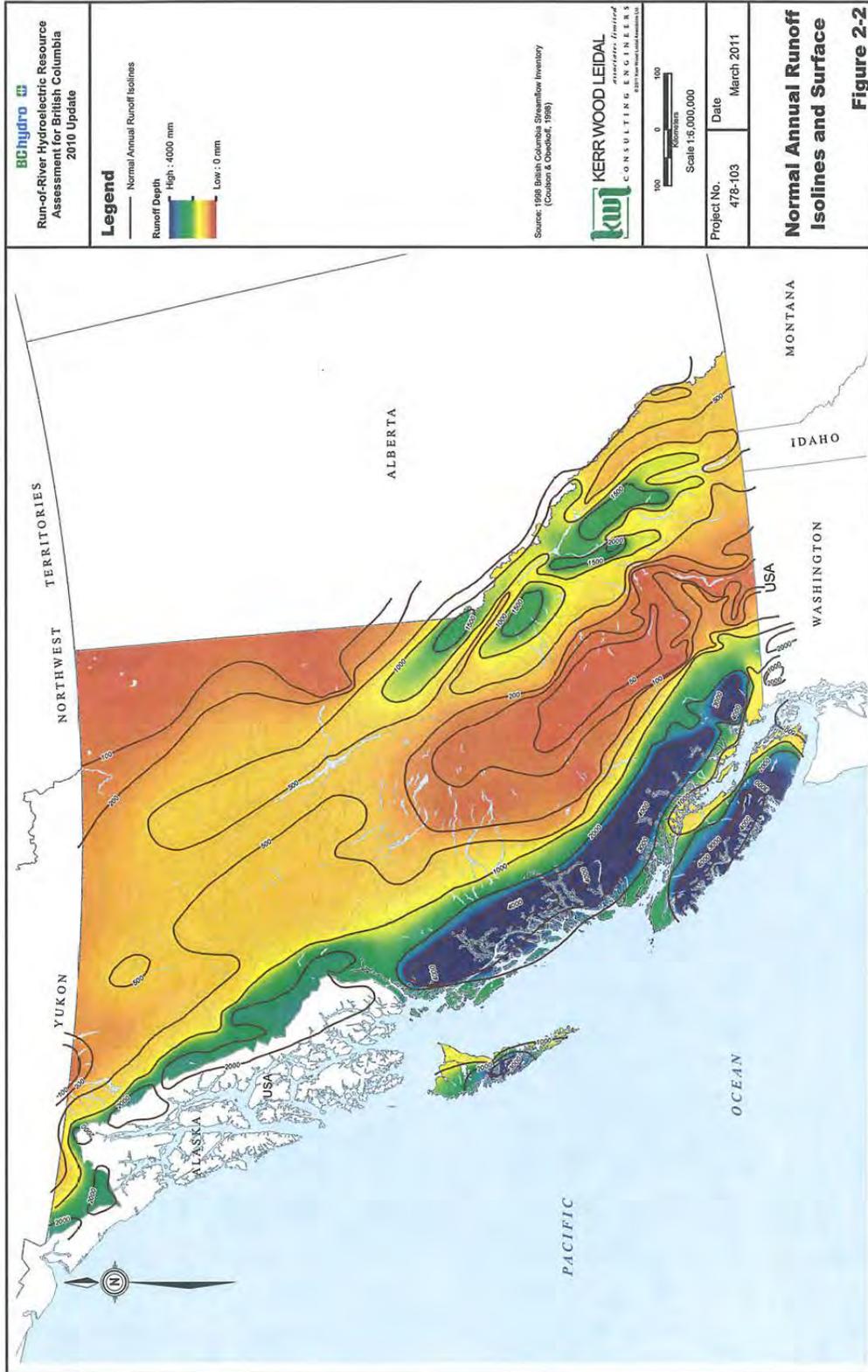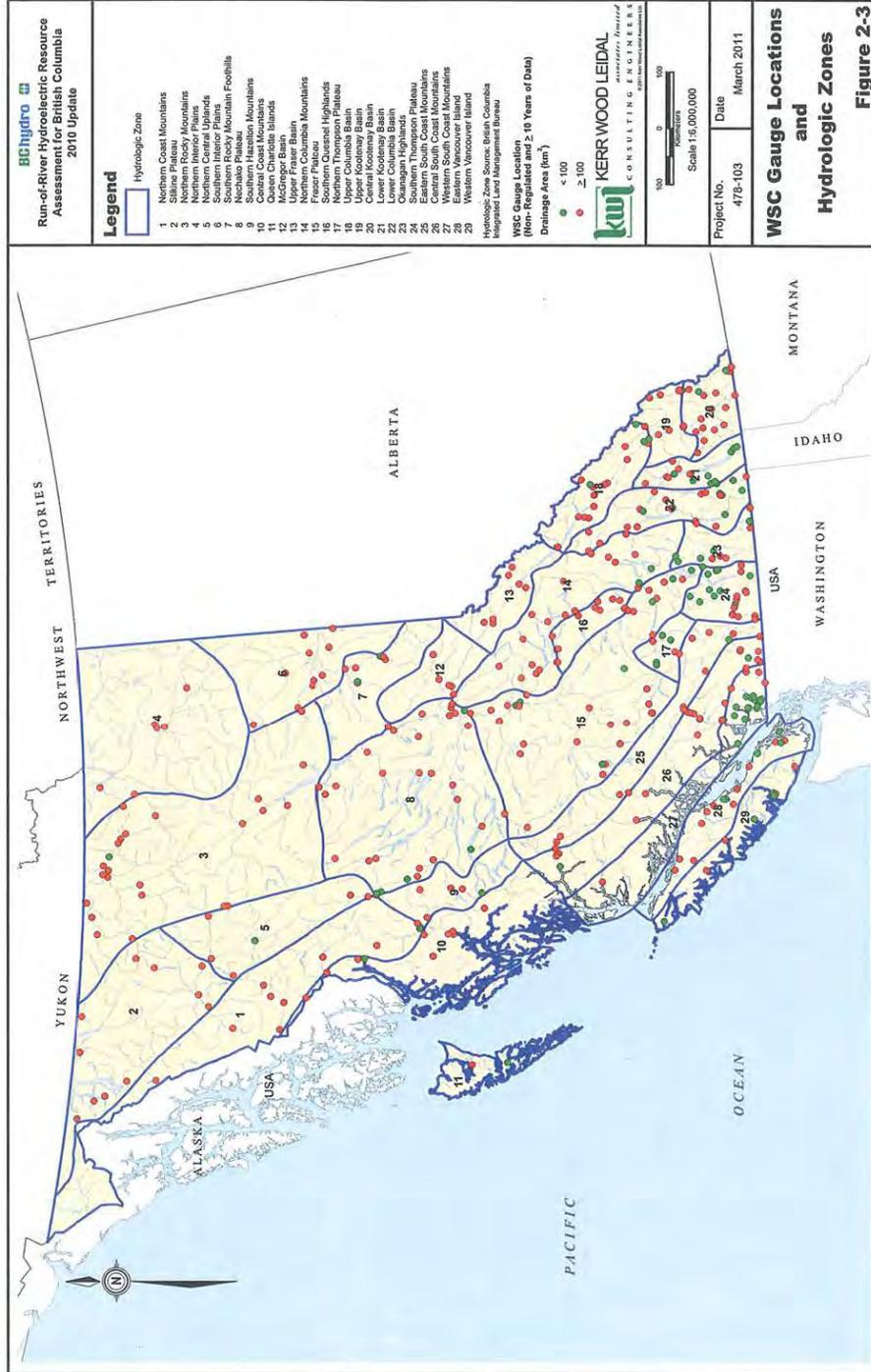
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3/25/2011 @ 11:09:45 AM

Hydrology (IN)

Digital Elevation Model (IN)

Normal Annual Runoff Isolines (IN)

Elevation Drop (OUT)

Flow (OUT)

In-Stream Power (OUT)

Dependable Capacity Average and Firm Energy (OUT)

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Run-of-River Hydroelectric Resource
Assessment for British Columbia 2010 Update

Project No.	Date		
478-103	March 2011	**GIS Rapid Hydro Assessment**	
		Model Process Flowchart	**Figure 2-4**

RUN-OF-RIVER HYDROELECTRIC RESOURCE ASSESSMENT
FOR BRITISH COLUMBIA 2010 UPDATE
FINAL REPORT – MARCH 2011   BC HYDRO & POWER AUTHORITY

FIGURES

TABLES

APPENDICES

Appendix A: Hydrologic Gauge Data
Appendix B: Roads & Power Lines Cost Estimation Using GIS
Appendix C: Hydropower Potential by Transmission Region
(Note: Appendices A, B & C are provided in a separate file on the BC Hydro Integrated Resource Plan website)

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3. COST AND ECONOMIC ANALYSIS

The following sections outline the assumptions and process to estimate capital and annual costs for hydro projects in the study area. Since this assessment is an inventory level study, the analysis and estimates of costs are intended to provide the magnitude of costs and to gauge relative costs between projects.

GENERAL DESCRIPTION AND LIMITATIONS

The capital cost estimates prepared for potential hydropower projects are of an inventory level.

The cost estimates include:

- Intakes, size based on design flow of project;

- Penstocks, based on diameter, slope and pressure rating (assuming steel pipe);

- Powerhouse, based on design flow of project (assumes pre-engineered building);

- Energy equipment, including turbine, generator and electric balance of plant (controls, protection and substation), based on head and power output;

- Road access;

- Power line connection to existing grid;

- Mobilization and transport costs, including camp (if required);

- Allowance for engineering: 15%;

- Bonding and insurance: 2%;

- Environmental and social mitigation allowance: 5%; and

- Interest during construction.

The cost estimates do not include the following site-specific considerations (not exhaustive):

- Geotechnical allowances;
- Market shortages of labour and/or materials; and
- Delays due to difficult construction conditions, terrain or weather.

The cost estimates include a 30% contingency allowance on civil items and a 10% contingency on generation equipment and electronic balance of plant. All costs are presented in 2011 $ Canadian dollars, and do not include any local, provincial or federal taxes.

3.1 METHODOLOGY

DATA COLLECTION AND RESEARCH

Kerr Wood Leidal Associates Ltd. staff have been involved in the development of hydro projects in British Columbia ranging from 1 to 50 MW in capacity. This experience was used to develop average quantities and their costs for individual project components (intake, powerhouse, penstock, generating equipment). This was accomplished by comparing component costs for projects that were either constructed or in an advanced stage of development where contractor and supplier quotes were available. This data was used to develop cost curves using regression. These comparisons showed that specific site conditions affect the cost of project components significantly.

Specifics to how this data was generated cannot be disclosed, as the information used to generate the cost curves is confidential.

The cost curves were also relevant for projects over 50 MW as the costs were developed on a component basis. There is greater uncertainty, however; with low head projects over 50 MW due to large water diversions that push the bounds of the cost curves. Of the projects identified in the study less than 0.2% have capacity over 50 MW.

3.2 CAPITAL COSTS

PENSTOCK

Known capital costs were obtained for typical penstock construction within British Columbia in Canadian dollars. These costs were used to calibrate cost curves that were developed for the assessment.

INTAKE AND POWERHOUSE CIVIL WORKS

Intake and powerhouse components were sized and costed based on experience with projects in British Columbia. These costs were used to calibrate cost curves that were developed for this assessment.

GENERATION EQUIPMENT – TURBINE/GENERATOR AND ELECTRIC BALANCE OF PLANT

Conceptual cost tables were based on actual projects and curves for projects were developed for a variety of project capacity, heads and flows. Cost estimates were developed for the supply and installation of energy equipment (e.g. turbine and generator) and electrical balance of plant (switchgear, controls, substation). The type of turbine (Kaplan, Francis or Pelton) selected for each project was based on the design head at each of the sites (Table 3-1) and the number of units based on design capacity (Table 3-2).

Table 3-1: Turbine Selection

Head	Turbine Type
8 – 40 m	Kaplan/Propeller
40 -200 m	Francis
200 – 1,000 m	Pelton

Table 3-2: Turbine No. of Units Selection

Kaplan		Francis and Pelton	
< 6 MW	N/A	< 5 MW	1 Unit
6 – 12 MW	1 Unit	5 – 30 MW	2 Units
> 12 MW	2 Units	> 30 MW	3 Units

ROAD AND POWER LINE COST

Information relating to the estimation of the cost for roads and power lines can be found in Appendix B.

CONSTRUCTION CAMP AND TRANSPORTATION

To account for site variations due to regional factors and remoteness (proximity to city centres), costs for construction camps and transportation of people and equipment were added to estimates.

Four site categories were used to indicate remoteness of location. Category A sites were located within a 50 km radius of a major town or city centre (population of 25,000 or more). Category B and C sites were located within 200 and 400 km from a centre, respectively, and Category D sites were located anywhere outside a 400 km radius from a centre. Figure 3-1 shows these site location categories.

Transportation costs included travel time to and from a site for the necessary construction crews as well as any overtime and air or ferry costs related to travel for the duration of construction. The construction period required for a potential project would vary depending on size. For the purposes of this study, construction periods of one, two, and three years were used for project capacities of less than 5 MW, five through 15 MW and greater than 15 MW respectively. The permitting, design and assessment periods were estimated to be three and five years for project capacities of less than 50 MW, and greater than or equal to 50 MW, respectively.

It was assumed that all category C and D projects would include a camp, which would be used during the construction period and could be downsized for use during operation. The components of the camp included sleeper, kitchen and office trailers, water supply and treatment equipment, sewage treatment, drainage systems and power supply. Costs for construction and set-up of the camp were also included. Operating costs are included in Section 3.3.

Camp and Transportation cost estimates for the construction periods for site categories A through D are shown in Table 3-3 below:

Table 3-3: Total Camp and Transportation Costs Including Mob/Demob ($)

Project Capacity	Location Class A	Location Class B	Location Class C	Location Class D
Less than 1 MW	111,300	222,600	800,830	934,390
1 to 10 MW	222,600	445,200	1,304,330	1,571,450
Greater than 10 MW	333,900	667,800	1,807,830	2,208,510

ENGINEERING, ENVIRONMENTAL AND OTHER

Project specific costs such as those for engineering or environmental management require detailed site information to determine. For inventory level estimates in this report, typical allowances expressed as a percentage of total capital cost are given to account for these cost items. In this study, allowances for each site category were as follows:

Table 3-4: Cost Allowances (% of Capital Cost)

Generating Equipment Installation[1]	Bonding and Insurance	Environmental	Engineering
10%	2%	5%	15%
1. Generating equipment installation only applied to Turbine/generator and Electric Balance of Plant costs.			

UNIT COST ESTIMATES

This section summarizes the dependant variables and assumptions used to determine unit costs for the following project components.

Penstock

Dependent variables:

- Diameter;
- Pressure rating; and
- Penstock gradient.

Assumptions:

- All pipes constructed of steel, lined and coated;
- Two average pipe pressure ratings: penstock average of 1,725 kPa (250 psi) and penstock average of 4,135 kPa (600 psi); and
- Slope of terrain ranges from 0 to 75+%.

Powerhouse, Intake and Miscellaneous Civil

Dependent variables:

- Plant design flow (1.5 times Mean Annual Discharge).

Assumptions:

- Blasting and construction (weir, gates, valves, etc.) Required at intake site; and
- Size of powerhouse and intake directly related to plant design flow.

Generation Equipment

Dependent variables:

- Turbines: number and type (Kaplan, Francis, Pelton); and
- Capacity: net head and flow.

Assumptions:

- Installation of generation equipment is 10% of equipment cost.

Electric Balance of Plant

Dependent variables:

- Number of turbines; and
- Capacity: net head and flow.

Assumptions:

- Installation of Electric Balance of Plant is 10% of equipment cost (excluding camp, access costs).

Power Line

Dependent variables:

- Voltage of power line;
- Capacity: net head and flow; and
- Terrain for construction.

Assumptions:

- All power lines constructed at 25 kV or above;
- 25 and 69 kV lines may be single pole, roadside construction; and
- Slope of terrain ranges from 0 to 75%.

Access Road(s)

Dependent variables:

- Availability of materials;
- Terrain for construction; and
- Difficulty of construction.

Assumptions:

- All new roads are 6 m wide;
- Includes clearing and decking of timber;
- Forestry type road construction with 0.3 m gravel topping;
- Portion of cut volume requires blasting; and
- Road grade ranges from 0 to 30%;

3.3 ANNUAL COST ANALYSIS

This section includes estimates of annual costs for operations and maintenance.

Estimated O&M Cost

Operations and maintenance costs were estimated to be 2% of total capital costs for at gate and access roads and 1.1% of total capital costs for power lines.

Water Rental and Taxes

Water rental fees were estimated in accordance with the "Annual Water Licence Rental Rates Associated with Power Production" document, revised December 11th, 2009. For authorized capacity, the charge is $4.345 per kW. For output, the charge is $1.304 per MWh/yr up to 160,000 MWh and $6.084 per MWh/yr up to 3,000,000 MWh.

Land Taxes

Property taxes were estimated to be 3% of the assessed property value, which was assumed to be 80% of the capital cost of the civil infrastructure.

Interest During Construction

Project lead-time interest was calculated by taking all development costs and dividing them into equal annual payments. Interest is than calculated annually until project COD is reached.

Project construction period interest was calculated by taking all construction costs (including equipment) and dividing them into equal annual payments. Interest was then calculated annually until project COD is reached.

3.4 LAND ALLOWANCE

A land allowance cost in the form of an annual cost that was included in consideration of the cost to purchase, lease or obtain permission through negotiations to use the land for the construction and operation of hydropower projects. An annual cost of 5% of the estimated assessed value (civil infrastructure) was included as an allowance for these highly variable, and difficult to predict costs.

3.5 UNIT ENERGY COST

Unit energy costs were calculated by amortizing the total capital cost as described in Section 3.2 for each project at a 6% real discount rate (and 8% as sensitivity) over 40 years, adding the annual costs described in Section 3.3 and dividing by the annual energy estimate for the site.
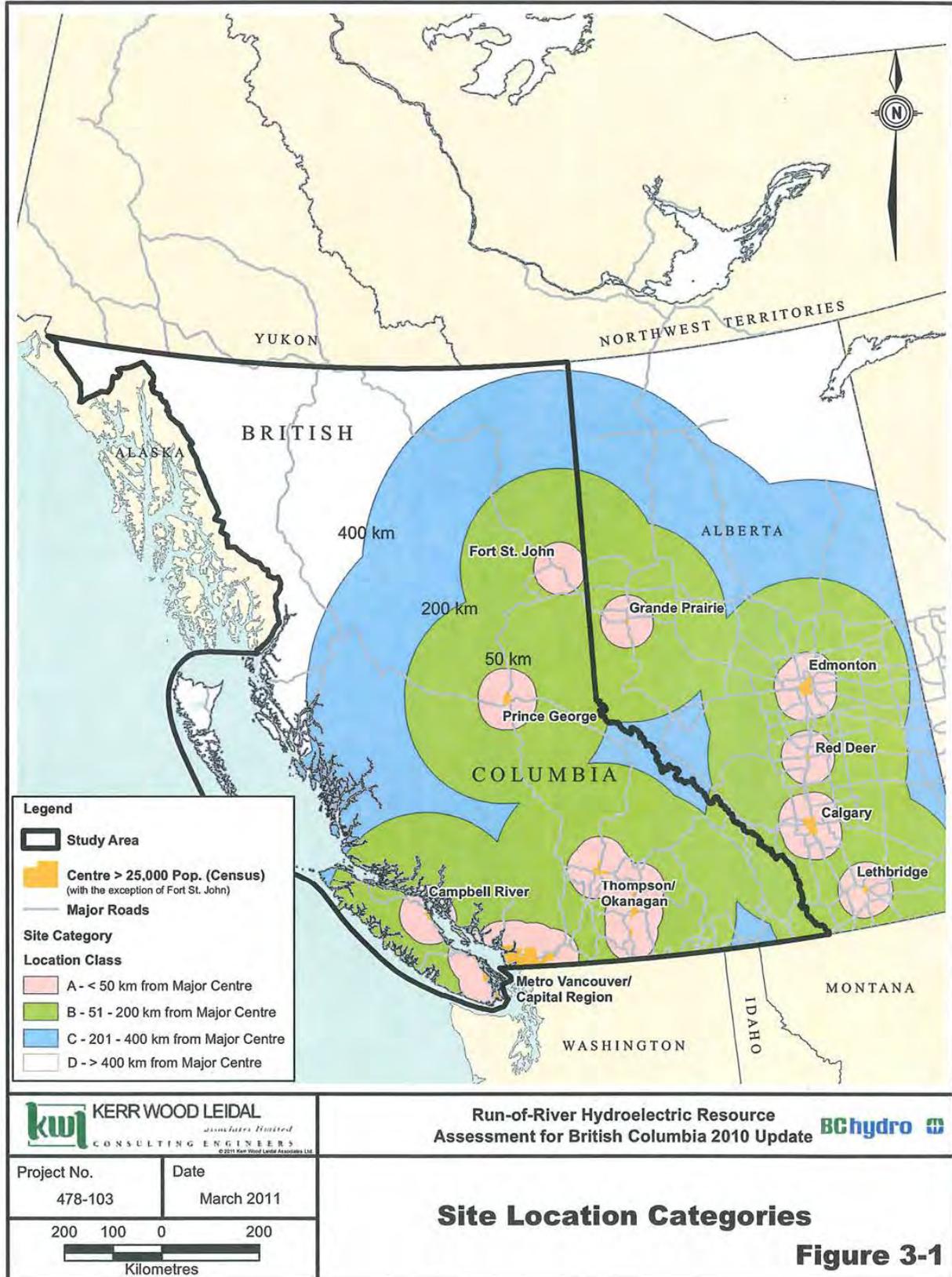
Site Location Categories

Figure 3-1

Run-of-River Hydroelectric Resource
Assessment for British Columbia 2010 Update

Project No.	Date
478-103	March 2011

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Legend
Study Area
Centre > 25,000 Pop. (Census)
(with the exception of Fort St. John)
Major Roads
Site Category
Location Class
A - < 50 km from Major Centre
B - 51 - 200 km from Major Centre
C - 201 - 400 km from Major Centre
D - > 400 km from Major Centre

Section 4

Results of Assessment

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4. RESULTS OF ASSESSMENT

4.1 POWER DEVELOPMENT POTENTIAL

The study identified over 7,200 potential run-of-river hydroelectric sites in BC. These sites have a potential installed capacity of over 17,400 MW and annual energy of nearly 63,000 GWh/yr. The estimated cost for each of the projects includes access roads and power lines interconnecting to the BC Hydro and Fortis BC grids. Table 4-1 provides the results with of the number of projects, energy and capacity by price bundle.

Table 4-1: Run-of-River Hydro Potential in BC

Price Bundle	Number of Projects	Average Annual Energy (GWh/yr)	Annual Firm Energy (GWh/yr)	Installed Capacity (MW)	Dependable Generating Capacity (MW)
65 - 69	1	89	66	20	2
70 - 74	3	212	172	53	1
75 - 79	3	664	503	173	6
80 - 84	5	930	698	222	17
85 - 89	3	177	142	45	0
90 - 94	7	698	531	167	12
95 - 99	9	684	556	179	8
100 - 109	30	2,135	1,708	543	34
110 - 119	46	3,512	2,710	847	61
120 - 129	22	1,251	1,045	330	8
130 - 139	36	1,706	1,379	443	18
140 - 149	44	1,920	1,549	486	27
150 - 159	39	1,971	1,584	492	25
160 - 169	37	1,427	1,189	376	8
170 - 179	47	1,758	1,449	473	15
180 - 189	40	1,401	1,141	363	14
190 - 199	51	1,330	1,098	357	5
200 - 299	452	10,320	8,321	2,820	63
300 - 399	399	6,149	4,978	1,732	31
400 - 499	365	4,204	3,331	1,193	16
500 - 599	277	2,163	1,733	637	9
600 - 699	241	2,015	1,575	570	8
700 - 799	230	1,621	1,255	472	5
800 - 899	193	1,578	1,229	445	5
900 - 999	177	1,124	875	322	3
1000 +	4,525	11,816	9,075	3,645	16
Total	**7,282**	**62,858**	**49,890**	**17,404**	**420**

A supply curve for run-of-river hydroelectric potential in BC is presented in Figure 4-1. The inventory identified potential sites that could contribute approximately 3,500 GWh/yr of new green energy in BC for under $100/MWh.

The unit energy costs do not reflect what an independent power producer may offer to sell electricity to BC Hydro due to factors such as:

- Cost of capital;
- Contract terms;
- Taxation; and
- Other factors.

The new methodology results in an estimated project size (capacity & energy) that is expected to better represent what a developer might construct for that reach of stream. In general it results in more capacity and energy and often with lower unit energy costs (UEC) than the 2007 study. The 2010 methodology provides a new inventory that is more representative of British Columbia's run-of-river hydroelectric potential.

The attached map of BC (Map E-1)[2] entitled *'Run-of-River Hydroelectric Potential in British Columbia'* shows the location of more than 7,200 sites with associated size and estimated unit energy cost.

4.2   POWER DEVELOPMENT POTENTIAL BY TRANSMISSION REGION

A summary of the results with the number of projects, energy and capacity by price bundle is broken down by transmission region and presented in Appendix C. Supply curves for run-of-river hydroelectric potential for the ten major transmission regions in BC are presented in Figure 4-2.

As this study involved identifying a complete inventory of potential run-of-river hydroelectric projects, the unit energy costs presented include both the most cost-effective and least cost-effective projects. There are 31 projects estimated to have a unit energy cost of under $100/MWh with approximately 900 MW of capacity and nearly approximately 3,500 GWh/yr of average annual energy. Table 4-2 below presents the run-of-river hydro potential for sites under $100/MWh by transmission region.

---

[2] Note: Map E-1 is provided in a separate file on the BC Hydro Integrated Resource Plan website.

Table 4-2: Run-of-River Hydro Potential in BC for Sites under $100/MWh

Transmission Region	Number of Projects	Average Annual Energy (GWh/yr)	Annual Firm Energy (GWh/yr)	Installed Capacity (MW)	Dependable Generating Capacity (MW)
East Kootenay	3	255	236	76	0
Kelly Nicola	6	873	658	228	8
Lower Mainland	17	1,328	1,025	323	16
North Coast	2	153	124	40	0
Revelstoke/Ashton Creek	1	67	51	17	1
Vancouver Island	2	778	573	175	21
Total	**31**	**3,455**	**2,668**	**858**	**47**

4.3 PROJECT COSTS AND UNIT ENERGY COSTS

Project costs and unit energy costs (UEC) were estimated for each site. UEC was calculated base on the average energy production, annual and capital costs. A 40-year amortization period was used to calculate UEC with a real discount rate of 6%, with a sensitivity at 8%. Each site was treated in isolation (i.e., no cluster development) with each site assumed not to share infrastructure with other projects being developed concurrently.

PROJECT SIZING

The results of the study demonstrate that large projects are often more economic than small projects. Projects greater than 30 MW in size comprise 55% of the energy in the less than $100/MWh range. This is about 23% of the projects in that cost range. Further, no projects less than 1 MW were under $150/MWh. Tables 4-3 through 4-5 provide a breakdown by project size and price bundle with totals of energy and capacity and number of sites.

Table 4-3: Energy by Project Size

Price Bundle	Annual Energy (GWh/year)			
	< 1 MW	1 to 30 MW	> 30 MW	Total
< $100/MWh		1,554	1,901	3,455
$100 to 149/MWh		6,722	3,803	10,525
> $150/MWh	5,293	40,441	3,144	48,878
Total	**5,293**	**48,718**	**8,847**	**62,858**

Table 4-4: Capacity by Project Size

Price Bundle	Installed Capacity (MW)			
	< 1 MW	1 to 30 MW	> 30 MW	Total
< $100/MWh		387	471	858
$100 to 149/MWh		1,714	935	2,649
> $150/MWh	1,729	11,386	782	13,897
Total	**1,729**	**13,487**	**2,189**	**17,404**

Table 4-5: Number of Sites by Project Size

Price Bundle	Number of Projects			
	< 1 MW	1 to 30 MW	> 30 MW	Total
< $100/MWh		24	7	31
$100 to 149/MWh		158	20	178
> $150/MWh	3,884	3,170	19	7,073
Total	**3,884**	**3,352**	**46**	**7,282**

Capacity was based on design flows of one and a half times mean annual discharge, the optimised penstock distance (and head), frictional losses and plant efficiency. As this is an inventory level study, there is likely to be more cost-effective configurations for each project site. Further analysis is required to optimise each project. The analysis did not consider diversion of tributary streams, multiple projects on a stream reach or other site-specific opportunities to decrease unit energy costs.

COST BREAKDOWN BY COMPONENT AND SITE REMOTENESS

The unit energy cost was greatly influenced by the remoteness of the site.

The supply curve presented in Figure 4-3 displays the UEC broken down by site infrastructure (at gate cost) and access / power line costs.

Breakdowns of cost by component for each site remoteness category (Site Categories A through D) are provided in average costs and percentages in Figures 4-4 and 4-5 respectively. Power line, access road, and mobilization costs are a substantially higher percentage of total costs for remote sites (Site Category D) than sites that are not remote (Site Category A).

CLUSTER DEVELOPMENT

Each site has access and power line costs estimated as if it is constructed in isolation of other projects. Since each site was treated in isolation, the unit costs are considerably higher in remote locations than they would be if areas were developed in clusters and infrastructure shared.

MAJOR ROAD AND TRANSMISSION LINE DEVELOPMENT

Cost-effectiveness (lower UECs) of many projects could be improved in remote areas if new major transmission lines or major roads were constructed with public resources.

MONTHLY ENERGY PROFILE

The monthly energy distribution of projects in each region can be found in Figure 4-6. The majority of energy is typically produced May through September during snowmelt periods, with the exception of Vancouver Island, which has less snow melt as a percentage of its runoff compared to the rest of the province.

UNIT ENERGY COST SENSITIVITY

The unit energy cost (UEC) sensitivity to real discount rate was explored. The UECs presented in this report were calculated using a 6% real discount rate. The UECs were also calculated at a real discount rate of 8% to compare against the results at 6%. Supply curves are shown on Figure 4-7 for both 6% and 8% real discount rates. Using a discount rate of 8% increased the capital amortization portion of each UEC by approximately 20% from total costs calculated using 6%.

4.4 CLOSING

There is large potential for future development of run-of-river hydroelectric projects in BC.

The study is an inventory level assessment and does not explore all of the options that could be available to developers at individual sites.

More comprehensive site investigation, First Nation discussions, environmental and social assessments, hydrologic data collection and analysis, and concept development is required for developers to proceed with potential project applications, licensing, electricity purchase agreements, and construction.

Supply Curve for Run-of-River Potential in BC at 6% Discount Rate
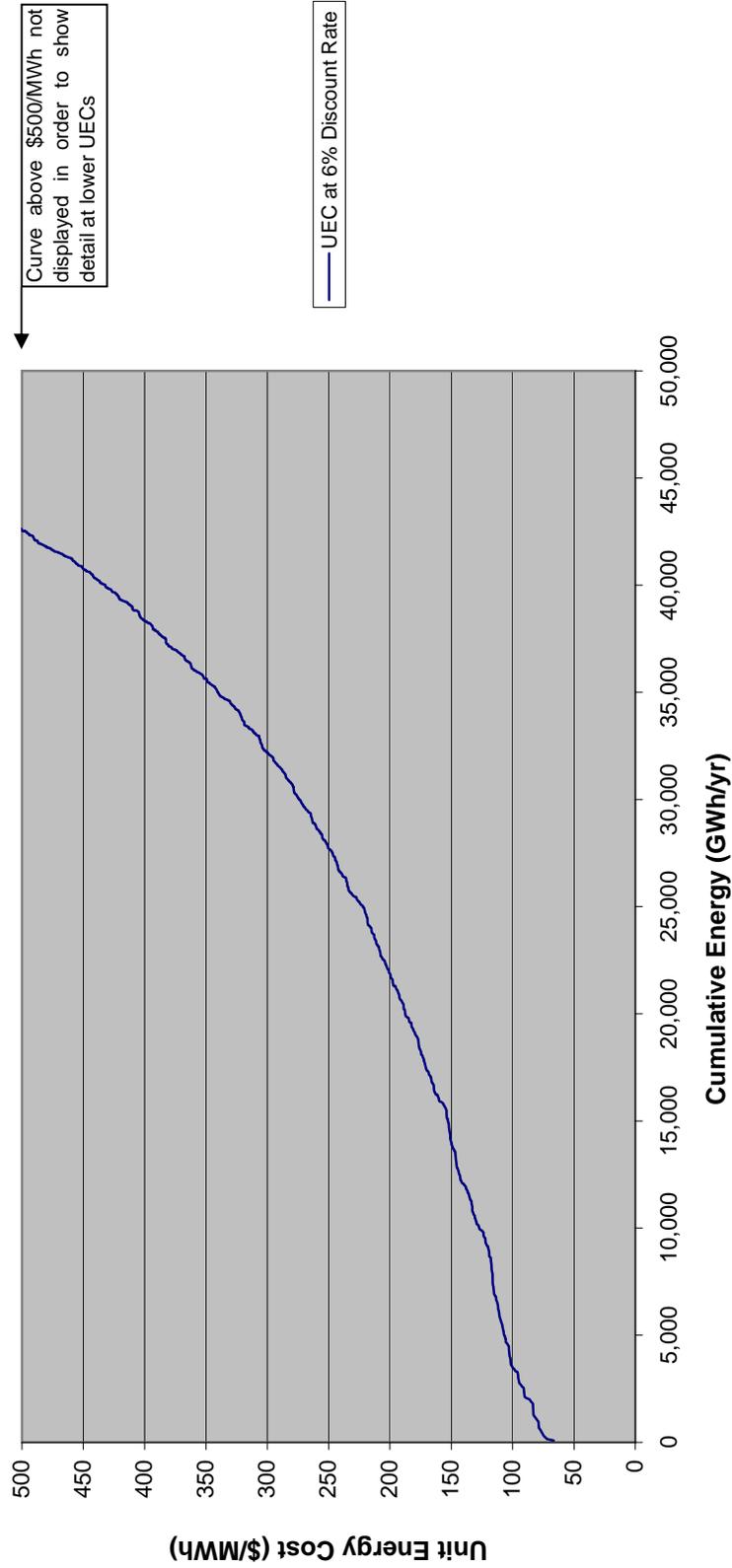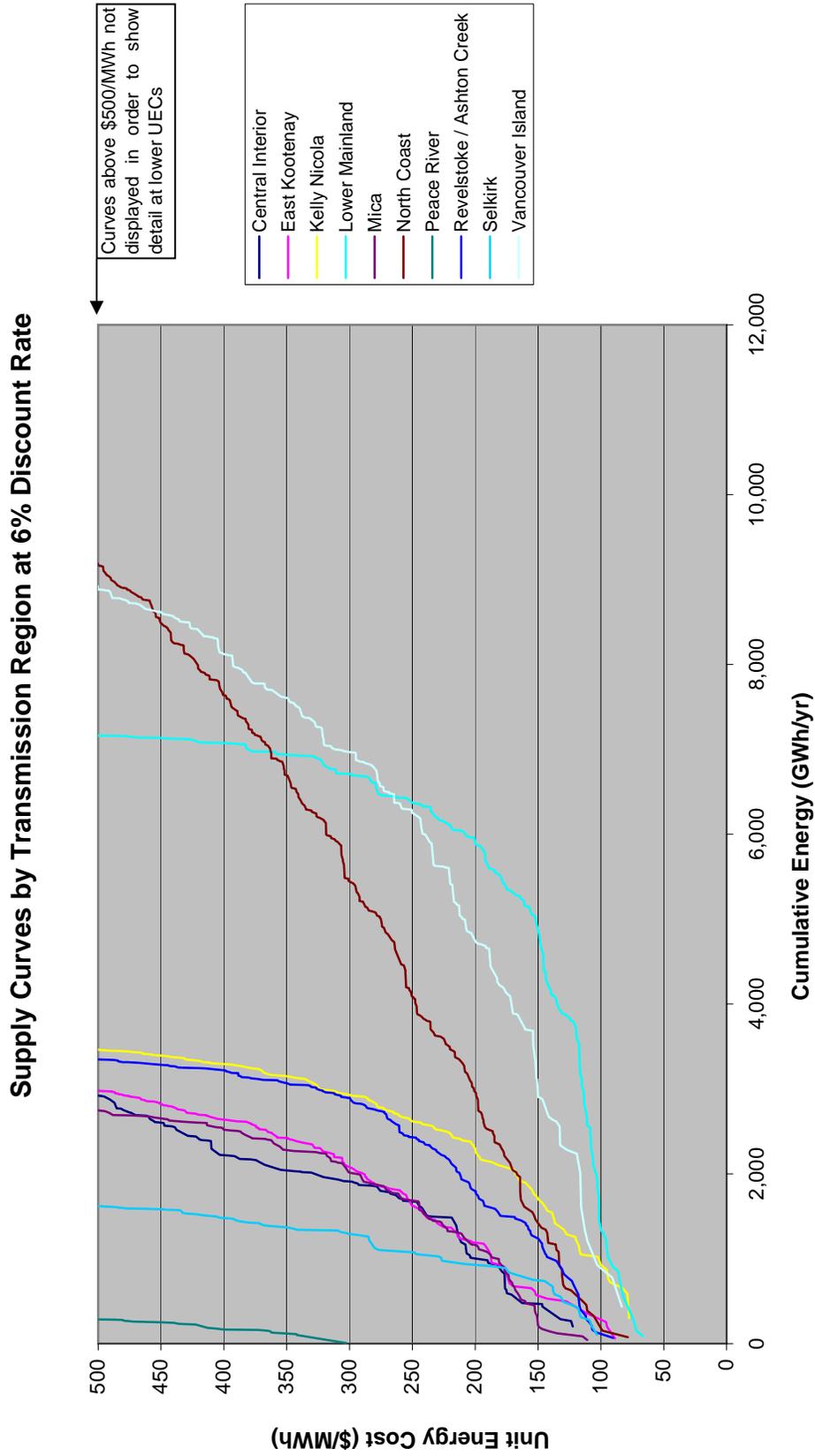
Figure 4-1

4-6

Supply Curves by Transmission Region at 6% Discount Rate

Curves above $500/MWh not displayed in order to show detail at lower UECs

Legend:
- Central Interior
- East Kootenay
- Kelly Nicola
- Lower Mainland
- Mica
- North Coast
- Peace River
- Revelstoke / Ashton Creek
- Selkirk
- Vancouver Island

Cumulative Energy (GWh/yr)

Unit Energy Cost ($/MWh)

RUN-OF-RIVER HYDROELECTRIC RESOURCE ASSESSMENT
FOR BRITISH COLUMBIA 2010 UPDATE
FINAL REPORT - MARCH 2011

BC HYDRO & POWER AUTHORITY

Supply Curve Breakdown for Run-of-River Potential in BC at 6% Discount Rate

Curves above $500/MWh not displayed in order to show detail at lower UECs

Legend:
- Average of UEC - Access/Powerline ($/MWh)
- Average of UEC - At Gate ($/MWh)

Unit Energy Cost ($/MWh)

Cumulative Energy (GWh/yr)

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4-8

Figure 4-3
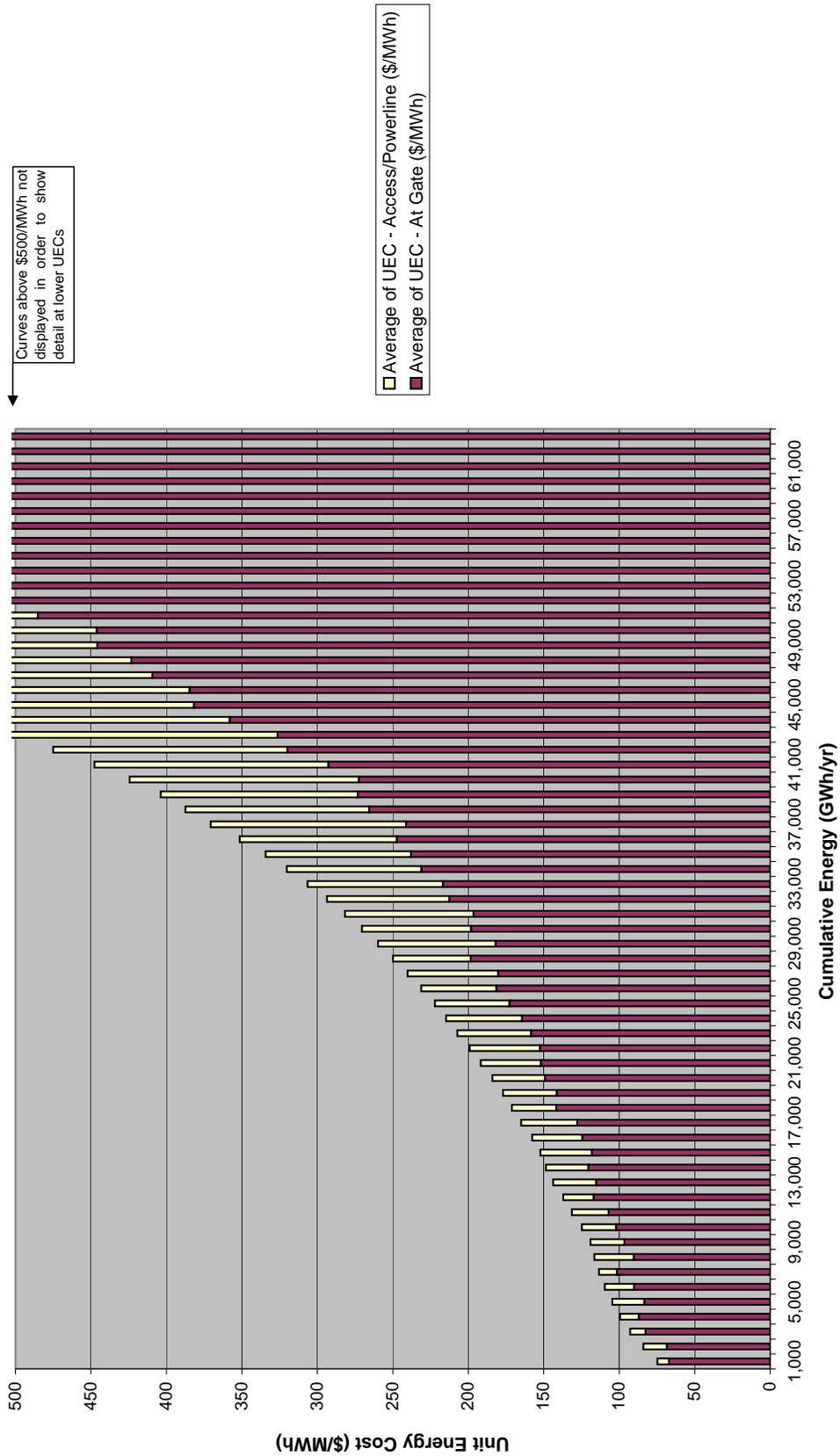
Average Site Category Cost Breakdown
(does not include Annual Costs or IDC[1])

Legend:
- Engineering
- General
- Mobilization
- Powerline
- Road
- Electrical
- Equipment
- Civil Works
- Penstock

Site Category A: < 50 km radius from a major town or city centre
Site Category B: 50 to 199 km radius
Site Category C: 200 to 399 km radius
Site Category D: > 400 km radius

1. Capital Costs only. Operations and Maintanence, Land and Water Taxes and Interest During Consturction not included.

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4-8

Figure 4-4

RUN-OF-RIVER HYDROELECTRIC RESOURCE ASSESSMENT
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Average Site Category Cost Breakdown as a Percent of Total
(does not include Annual Costs or IDC)[1]

Legend:
- Engineering
- General
- Mobilization
- Powerline
- Road
- Electrical
- Equipment
- Civil Works
- Penstock

Category A   Category B   Category C   Category D

Percent of Total Project Cost

Site Category A: < 50 km radius from a major town or city centre
Site Category B: 50 to 199 km radius
Site Category C: 200 to 399 km radius
Site Category D: > 400 km radius

1. Capital Costs only. Operations and Maintenence, Land and Water Taxes and Interest During Construction not included.

4-10

Figure 4-5

Monthly Energy Profiles - Small Hydro Potential By Transmission Region

Figure 4-6

4-11

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Supply Curve with Unit Energy Cost Sensitivity to Discount Rate

Curves above $500/MWh not displayed in order to show detail at lower UECs

UEC at 6% Discount Rate
UEC at 8% Discount Rate

Unit Energy Cost ($/MWh)

Cumulative Energy (GWh/year)

4-12
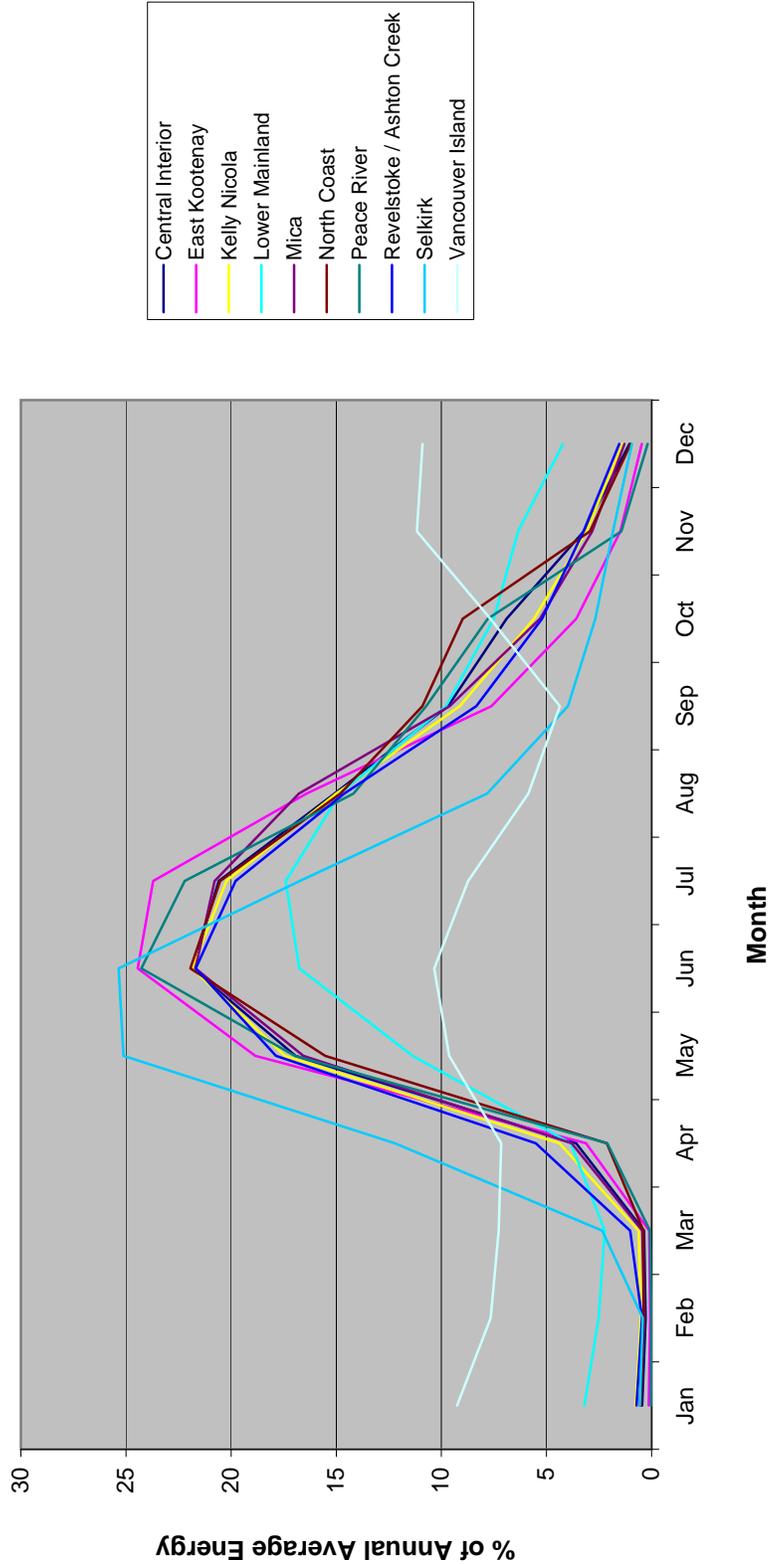
Figure 4-7
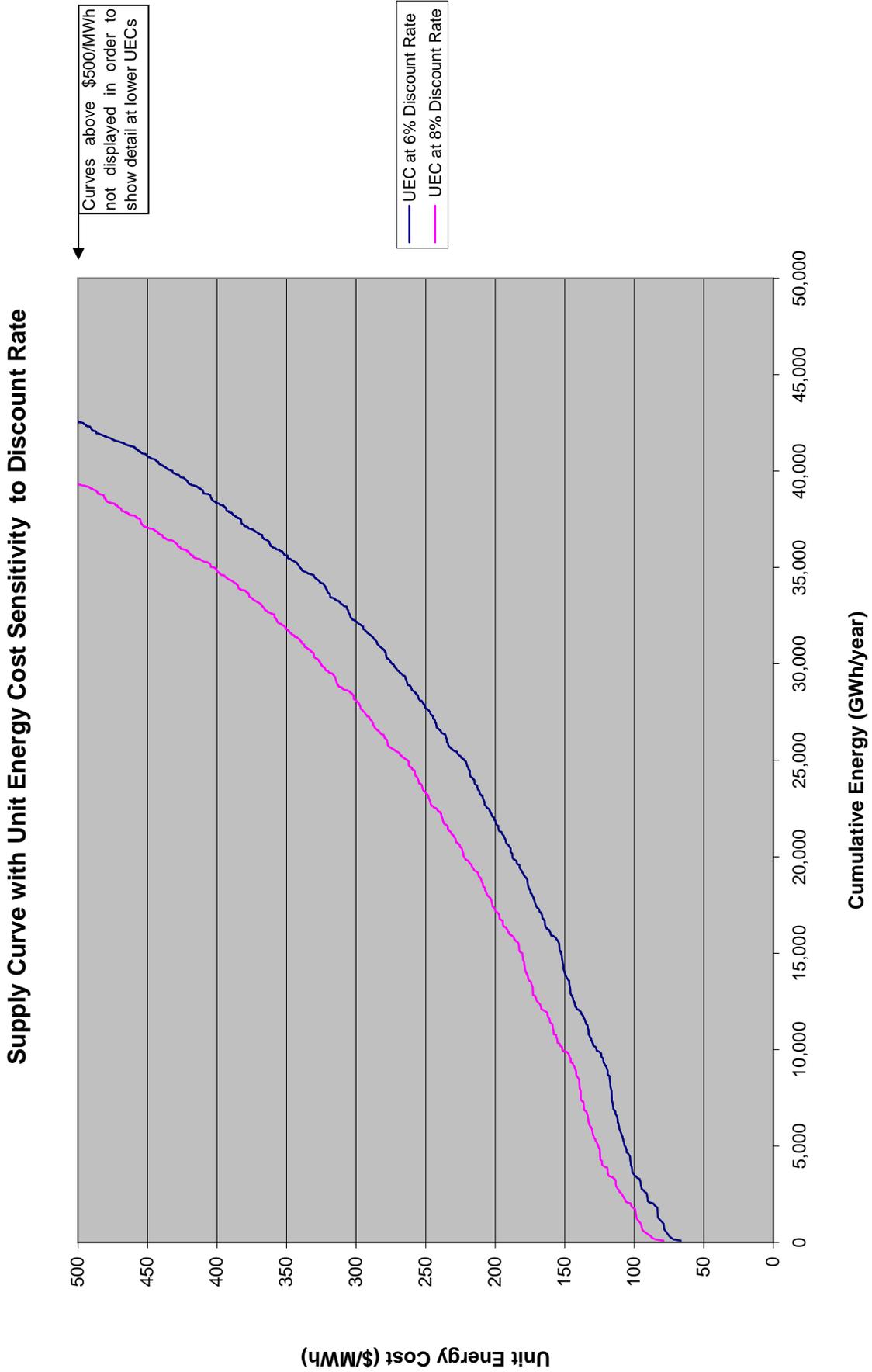
Section 5

Report Submission

5. REPORT SUBMISSION

Prepared by:

KERR WOOD LEIDAL ASSOCIATES LTD.

ORIGINAL SEALED BY

_____
Stefan Joyce, P.Eng.
Project Manager

Reviewed by:

ORIGINAL SEALED BY

_____
Ron Monk, M.Eng., P.Eng.
Senior Project Reviewer