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AN ASSESSMENT OF HYDROELECTRIC POWER OPTIONS TO SATISFY OIL SANDS ELECTRICITY DEMAND

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Executive Summary

The oil sands sector in Alberta is an important player in the global petroleum supply chain and a major contributor to the provincial and Canadian economy. Extracting and upgrading bitumen is an energy-intensive process where large amounts of thermal energy and electricity are utilized. The energy-intensity of its operations, in addition to heightening the marginal cost of production, have made the oil sands sector a dominant greenhouse gas (GHG) emitter in Alberta. With growing concerns about climate change, GHG-intensive operations have created a challenging environment for the oil sands sector. Consequently, oil sands operators and the provincial government are exploring options to reduce GHG emissions. Decarbonizing the electricity consumed by oil sands operations is one option to reduce GHG emissions.

Hydropower is a proven option to deliver a reliable supply of low carbon electricity. It is a major source of electricity generation in Canada. A high potential to develop new hydropower plants is available within Alberta and neighbouring jurisdictions. However, development of new hydropower plants requires long distance transmission lines to connect the oil sands region to sites with high hydropower generation potential. Furthermore, development of hydropower plants and transmission lines can potentially have land use impacts with greater environmental and social implications. This study identifies six options to generate and transmit hydropower to the oil sands region in Alberta and provides a multi-attribute evaluation of those options. This study also provides comprehensive economic assessments and high-level land use impact evaluations. The reference electricity generation option used in this analysis is natural gas-fired cogeneration units.

This study assesses new hydropower development options available in Alberta, British Columbia (BC) and Manitoba. Two long distance electricity transmission technologies – high voltage direct current (HVDC) and high voltage alternating current (HVAC) – were assessed as options to transmit hydropower to the oil sands region. The six hydropower generation and transmission options assessed in this report are summarized in Table E.1.

Table E.1: Summary of Hydropower Generation and Transmission Options

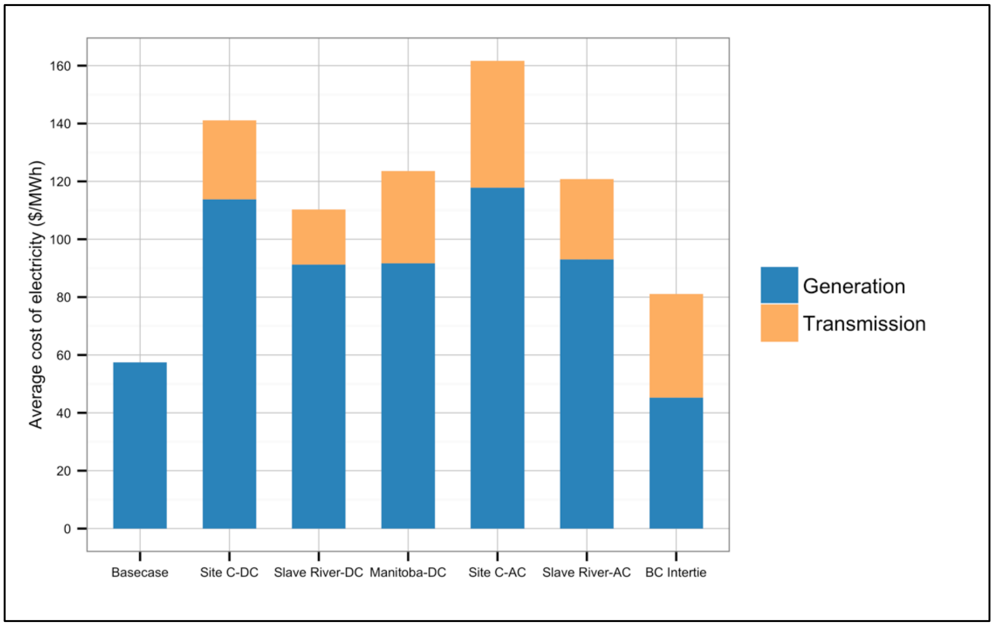
Option	Hydropower Generation Plant			Transmission System		
	Site and River System	Province	Rated Capacity (MW)	Technology	No. of Lines	Length (km/line)
Site C-DC	Site C on the Peace River	British Columbia	1100	±500 kV HVDC bipole	1	600
Site C-AC	Site C on the Peace River	British Columbia	1100	Single circuit 500kV HVAC	2	600
BC Intertie[i]		British Columbia	Increase by 500	Single circuit 500kV HVAC		
Slave River-DC	Alternative 4 site on the Slave River	Alberta	1100	±500 kV HVDC bipole	1	400
Slave River-AC	Alternative 4 site on the Slave River	Alberta	1100	Single circuit 500kV HVAC	2	400
Manitoba DC	Conawapa site on the Nelson River	Manitoba	1485	±500 kV HVDC bipole	1	1100

[i]The BC Intertie option assumes a case where the existing BC-AB intertie is reinforced to import higher amounts of hydropower purchased from the BC Hydro system. Therefore, no new hydropower plants or new transmission lines are attributed to this option.

Source: CERI

Figure E.1 depicts the average cost of delivered electricity (taking into account both generation and transmission cost; measured in $/megawatt hour [MWh]) under the six hydropower options. The reference case is also shown.

Figure E.1: Average Cost of Delivered Electricity of Different Generation and Transmission Options

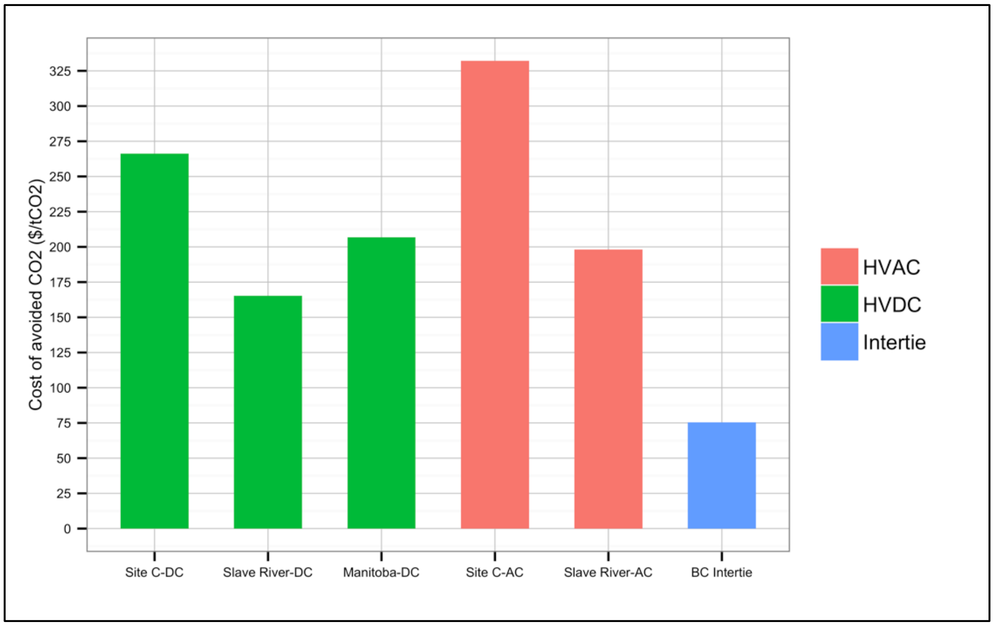


Note: All costs are in 2014 Canadian dollars.

Source: CERI

Figure E.2 shows the GHG emissions abatement cost (measured in $/tonne of carbon dioxide equivalent [tCO_2e]) of the hydropower options. GHG emissions abatement costs are calculated in comparison to the cogeneration reference case.

Figure E.2: Cost of Avoided GHG Emissions ($CACO_2$)



Source: CERI

Each of these six hydropower options can deliver sufficient electricity to satisfy the demand of in-situ bitumen extraction operations with production capacity of 0.5 million bbl/day to 1.1 million bbl/day. The average cost of delivered electricity is in the range of $81-$162/MWh.

In contrast, natural gas-fired cogeneration would cost about $57/MWh. Hence, without a price on GHG emissions, the likelihood of hydropower options reducing the marginal cost of oil sands operations is low. As a carbon emissions mitigation option, utilizing hydropower can potentially reduce the GHG emissions of oil sands operations by 13-16 percent at a cost of $75-$332/tCO_2e.

The lowest average cost of delivered electricity and GHG emissions abatement cost results from purchasing hydropower from the BC Hydro system and delivering it by utilizing the existing transmission intertie between Alberta and BC (BC Intertie option). This option requires implementation of mitigation measures to enable the full capacity utilization of the Alberta-BC intertie. The BC Intertie option also has the advantage of being able to deliver low GHG-intensive electricity in the near term (within 2-5 years). Furthermore, as the BC Intertie option would utilize existing electricity infrastructure, it would lead to zero to minimal new environmental and social impacts.

Compared to the other new hydropower options assessed in this study, the Manitoba DC option has a number of advantages. The Manitoba DC option has the lower average cost of delivered electricity compared to the two new BC hydropower options. The average cost of delivered electricity is very close to the Slave River-DC option and lower than the Slave River-AC option. The Conawapa hydropower project, which is the generation option pertaining to Manitoba DC, is in the advanced planning stage and Manitoba Hydro has already completed feasibility assessments.

Hydropower generation and transmission options assessed in this study have the ability to reduce GHG emissions of oil sands operations by decarbonizing the electricity consumed for bitumen extraction and upgrading. However, GHG emissions from bitumen extraction and upgrading are dominated by the emissions associated with the thermal energy portion. Therefore, with a larger supply of hydroelectric power, it is possible to achieve deeper emissions in the oil sands sector by deploying electrical extraction technologies for in-situ recovery of bitumen.

The reference case used in this analysis is onsite cogeneration. Adding onsite cogeneration to an oil sands operation requires additional investments and increases operational complexity. Therefore, it is also plausible that the oil sands operators may choose to purchase electricity from the Alberta electricity market, instead of onsite generation. In that situation, the reference case could be the grid average cost and emissions of an average price of $66/MWh and higher emissions of 710 KgCO_2/MWh. The reference case could also be the highest emissions source – coal-fired generation – using a coal-based electricity price of $83/MWh and emissions of 820 KgCO_2/MWh. This latter option is being phased out in Alberta but still forms a plausible reference case to compare displacement costs. If these six hydroelectricity options were considered, the carbon emissions abatement cost changes as shown in Table E.2.

Table E.2: LCOE and $CACO_2$ ($/$tCO_2e$) Estimates Compared to Different Reference Cases

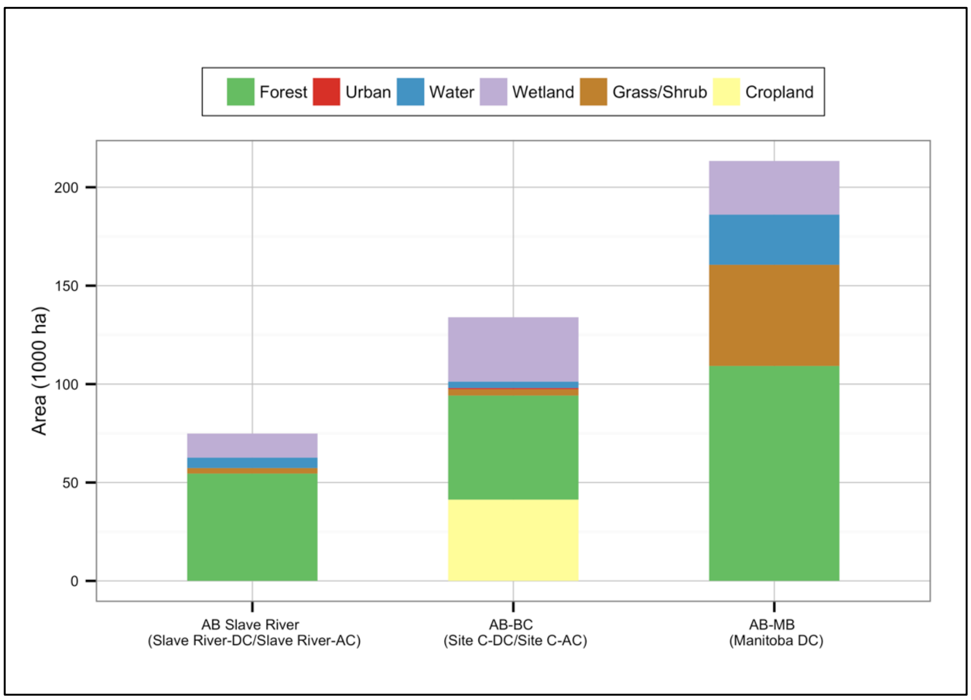
	HVDC Options			HVAC Options		Intertie Option
	Site C-DC	Slave River-DC	Manitoba DC	Site C-AC	Slave River-AC	BC Intertie
LCOE	141	110	124	162	121	81
$CACO_2$ – Cogen	266	165	207	332	198	75
$CACO_2$ – Grid Avg.	107	62	82	137	77	21
$CACO_2$ – Coal	72	33	50	98	47	-3

Source: CERI

Abatement costs are sensitive to the reference case. For the situation replacing new coal-fired generation with the BC Intertie, the abatement cost is negative because the cost of BC-intertie electricity is less than coal-based generation.

Figure E.3 depicts the land cover within the direct impact area of the hydropower generation and transmission options. In this study, the direct impact area is defined as the area formed by a combination of a 1 km wide buffer that encloses the selected transmission line corridor and a circular buffer with a 10 km radius that encloses the hydropower plant.

Figure E.3: Land Cover within the Direct Impact Area of the Hydropower Generation and Transmission Options



Source: CERI

As depicted in Figure E.3, due to the greater transmission distance, the Alberta-Manitoba option (Manitoba-DC) has the highest land use impact while the shorter transmission distance makes the Alberta hydropower options (Slave River-DC/AC) the ones with the lowest land use impacts.

However, careful assessment of the land cover reveals some interesting findings. Of the new hydropower options, the Alberta-BC options (Site C-DC/AC) have the highest agricultural and residential (in terms of populated areas within the direct impact area) impacts. Despite the longer transmission distance, the Alberta-Manitoba option has the lowest residential impacts. In all cases, the majority of the populated areas that would be impacted by new hydropower options are within Alberta. Alberta Slave River options would likely have the highest amount of environmental impacts in terms of the environmentally sensitive areas within the direct impact area. Environmental impacts could be exacerbated by potential impacts on the Wood Buffalo National Park and the Peace-Athabasca Delta, a wetland ecosystem with global significance. Moreover, these two options would have the highest impacts on aboriginal populations in terms of the number of First Nations reserves within the direct impact area.