Hydrogen Options within an Energy Strategy for Canada

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Hydrogen is a positive alternative to CO_2 emitting energy, and as such, deserves serious consideration as one element of a national energy strategy. No direct CO_2 emissions result from the conversion of energy from nuclear, wind, solar and hydro generation into hydrogen through electrolysis of water, and it can be readily transported from production sites to where it will be used.

Petroleum based energy will play a significant role well into the future. As a consequence, hydrogen will be needed in large quantities for continued development of the Alberta oil sands. It also has the potential to solve some transportation emission problems in large urban areas where air pollution is causing significant health problems with associated costs.

The significance of this is that if the electrical energy is cleanly generated, hydrogen produced from this energy has no CO_2 (GHG) output beyond initial capital implications. Compare this to stripping hydrogen from natural gas, as is done presently in the oil sands, with substantial CO_2 output. Cosmos Voutsinos[1] notes that the process for extracting and upgrading bitumen from the oil sands requires 1000 cubic feet (35.31m3) of natural gas that includes the production of 5 kg of hydrogen: the amount needed for 1 barrel of crude oil. The resulting emissions of CO_2 represent the greater portion of emissions from the oil sands. To separate the oil from the sand and process it results in 200 pounds of CO_2 per barrel produced. Current output from the oil sands is in the order of1.3 million (with plans to go to 5) barrels each day. Consequently almost 400,000 MT of CO_2 enter the atmosphere daily from current operations.

Demand for hydrogen world-wide is increasing. Germany is building hydrogen fuelling stations; and Japan and Korea, now hugely dependent on energy imports are also moving towards greater use of hydrogen in transportation. Interestingly, hydrogen powered buses at Whistler receive their hydrogen from Quebec via truck. If this is practical, shipments by rail, sea or pipeline are clearly competitive. Canadian demand is projected to grow from 3 million metric tons (MMT) to 6 MMT in the next 13 years, largely for the oil sands. World demand was 32 MMT in 2007, and is projected to increase to 50 MMT in 2012 and 79 MMT by 2016: more than doubling in 8 years.

Cost of production has been an impediment to hydrogen use, but competitiveness would change if a price/charge/tax were put on CO_2 production. Or, alternatively, regulations could be

[1] See Cosmos M. Voutsinos, "Road Map for a Comprehensive Energy Policy", The McIntyre Collegium, January, 2010

introduced favouring electrolysis (or any other CO_2 free process) over steam methane reforming to produce hydrogen. As the price of natural gas increases from current levels of under $5/Gj (limited reserves), hydrogen could become an attractive option.

Wind and solar energy “farms”, generally, produce energy according to wind and radiation available at any point in time, implying considerable costs when such variability is introduced to an electrical grid, because offset generation capacity is needed. If wind or solar energy is used off grid to produce hydrogen, the hydrogen can be stored (as if it were a battery) and used for transportation, oil sands expansion or other purposes. Relatively inexpensive hydro power, especially from remote locations, can be converted into hydrogen and shipped to market, instead of sending electricity via long distance direct current transmission lines with associated line losses and converter costs. Nuclear plants also have inexpensive base load capability, and can be located close to markets e.g. oil sands. Hydrogen can also be shipped through pipelines. Moreover, energy surpluses during periods of low demand (e.g. overnight) could be used to produce hydrogen at very low cost.

Not all hydro locations would be practical, but in Canada two excellent examples stand out: Northern Manitoba and Labrador. The Nelson River still has undeveloped capacity, is close to Thompson with underutilized infrastructure, and close to a rail line to both Churchill and The Pas and beyond. Hydrogen could easily be shipped to Alberta by rail. Shipments could be made to Europe via rail and ship from Churchill, especially if ice becomes less restrictive in Hudson’s Bay and the Hudson Strait. In Labrador, electrolysis of water with hydro power from the Lower Churchill could produce hydrogen for shipping anywhere in the world, avoiding any potential transmission costs like those that continue to plague the original Churchill Falls plant. In either case, either all or some portion of the total electricity produced could be used for the electrolysis process. Given that electrolysis at high temperatures produces hydrogen much more efficiently, teaming a hydro plant with a nuclear one would make an effective and competitive combination. A nuclear plant can produce a lot of hot water. Then both the nuclear plant and the hydro plant can provide the energy for high temperature electrolysis, using the discharged water from the nuclear plant. Although there will be some boil-off losses during shipment of liquefied hydrogen, such shipments would still be viable: electrical transmission lines lose energy too.

If, for example, the Limestone generating station on the Nelson River were dedicated to hydrogen production, and operating at capacity, 220,000 MT per year of hydrogen could be produced, reducing CO_2 emissions from oil sand production and releasing it, for example, to replace coal generation plants in Saskatchewan. The hydro plant could be combined with a 1200 MW nuclear plant with base output (using cold water) of 185,000 MT per year. If discharged hot water from the nuclear cooling process was used for the electrolysis process for both hydro and nuclear generators, the additional 25% additional output from the use of hot water would result in a combined output of about 500,000 MT. Approximately the same output could be projected from a combined hydro-nuclear operation on the Lower Churchill.

Current technology using natural gas to upgrade bitumen requires significant water resources plus 35.3 cubic metres of gas to produce 5 kg of hydrogen for each barrel of crude oil. Regardless of how world output and consumption of energy types change in the next 40 years, petroleum based energy will continue to be significant, and given the size and relative security of the Alberta oil sands, extraction will continue to grow. The rate of growth, however, will be directly affected by its ability to significantly reduce CO2 emissions. If the Alberta oil sands will need an additional 3MMT of hydrogen in the next 15 years for increased operations, current methane stripping technology will produce an unacceptable amount of CO2. Even using a new development estimated to reduce CO2 emissions by 25% implies major increases. The existing sources of natural gas plus the new forecast for CH4 from coal seams will hardly last 50 years at projected output rates, yet the oil reserves are so large that oil can be extracted for hundreds of years. Where will the hydrogen come from for upgrading bitumen to crude oil unless new options are put on the drawing board in the near future?

The long time periods from decision to production in all major energy projects means that thought must be given now to the energy mix Canada will need in 2040, 2050 and beyond in order to meet its own demand plus export opportunities. Analysis is required to address several obvious problems: cleaner oil sands production; markets and transmission options for hydro in Manitoba and British Columbia; growing demand in Ontario at a time when existing high CO2 emission coal plants are closed; closure of similar Saskatchewan coal plants; and market and transmission options for power produced in Newfoundland and Labrador.

It is now time for hydrogen, along with increased electrical output from nuclear and natural gas, to be explored as key elements of a broader energy vision for Canada. In the absence of any apparent federal political interest in an urgently needed national energy strategy, a good start could be made by the appropriate Premiers beginning the work of defining an energy policy and strategy for Canada in consultation with all energy industries. Canada's very future will depend on comprehensive energy synergy by the Provinces, with the Federal Government of necessity facilitating such synergy to occur.

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