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Hydrogen production from wind energy in Western Canada for upgrading bitumen from oil sands

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ABSTRACT

Hydrogen is produced via steam methane reforming (SMR) for bitumen upgrading which results in significant greenhouse gas (GHG) emissions. Wind energy based hydrogen can reduce the GHG footprint of the bitumen upgrading industry. This paper is aimed at developing a detailed data-intensive techno-economic model for assessment of hydrogen production from wind energy via the electrolysis of water. The proposed wind/hydrogen plant is based on an expansion of an existing wind farm with unit wind turbine size of 1.8 MW and with a dual functionality of hydrogen production and electricity generation. An electrolyser size of 240 kW (50 Nm^3 H_2/h) and 360 kW (90 Nm^3 H_2/h) proved to be the optimal sizes for constant and variable flow rate electrolysers, respectively. The electrolyser sizes aforementioned yielded a minimum hydrogen production price at base case conditions of \$10.15/kg H_2 and \$7.55/kg H_2. The inclusion of a Feed-in-Tariff (FIT) of \$0.13/kWh renders the production price of hydrogen equal to SMR i.e. \$0.96/kg H_2, with an internal rate of return (IRR) of 24%. The minimum hydrogen delivery cost was \$4.96/kg H_2 at base case conditions. The life cycle CO_2 emissions is 6.35 kg CO_2/kg H_2 including hydrogen delivery to the upgrader via compressed gas trucks.

1. Introduction

The international obligations of Canada that pertain to the mitigation of greenhouse gas (GHG) emissions under the United Nations Framework on Climate Change (UNFCC) and Kyoto protocol [1], have fuelled research and development efforts to produce sustainable energy pathways with little or no environmental impact. The notion that a vibrant hydrogen economy is required for Canada and other developed nations to mitigate their GHG emissions has achieved wide spread consensus in literature [2–7,17]. The potential of hydrogen as the energy carrier for the future, particularly in the transportation and power generation sectors in Canada has been the subject of extensive work by number of authors [3–13]. The existing research into hydrogen production from a Canadian perspective is multi-faceted with regards to the motivation and insight provided by the work carried out. Some authors have focused on the use of a particular renewable resource such as nuclear energy, biomass, and solar energy to power hydrogen production [7–11], while others have utilised renewable energy technologies in tandem with one another for the same purpose [6,12,13]. Furthermore, some authors have proposed the effective utilisation of existing energy infrastructure in Canada, which is a mix of renewable and non-renewable resources to facilitate hydrogen production [3,4].

In all the various strategies proposed by the authors aforementioned, the means through which hydrogen is produced is dominated in most part by two processes, namely: (a) water electrolysis (b) thermo-chemical water splitting cycles (TWC). Sustainable hydrogen production via nuclear powered thermo-chemical cycles in particular, has been explored extensively by some authors [6–8]. This has lead to the realisation of the favourable properties of the copper-chlorine thermo-chemical cycle in comparison to other viable TWCs [7,8]. The relatively low process heat requirement of the Cu–Cl cycle which translates into reduced maintenance and material costs is particularly significant [8]. Although nuclear/thermo-chemical hydrogen production enjoys the advantage of large scale hydrogen output in comparison to other sustainable pathways such as wind and solar [7] - the environmental impacts highlighted by Naterer et al. (2009) [8] and the public perception of the risks associated with nuclear energy present a formidable resistance to its market penetration.

Still focusing on the Canadian context, it was observed that in all the different hydrogen production pathways put forward, the availability of cheap, off-peak energy was a pre-condition for hydrogen production. This practice is usually adopted so as to minimise the production cost of hydrogen against the fossil fuel

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dependent alternative (i.e., SMR). However, it is worth mentioning that the production of hydrogen in the published literature is not necessarily used to displace other conventional hydrogen production pathways such as steam-methane reforming (SMR) [3–6,12,13]. Some efforts are concentrated on the production of hydrogen for consumption in the transportation sector by fuel-cell vehicles [3–5]; alternatively, the production and storage of hydrogen solely for electricity generation, either for remote, grid independent applications, or grid connected utility scale electricity supply have been proposed by some authors [6,12,13]. In these studies [6,12,13], hydrogen is used to provide additional electricity output, improve reliability, or remedy lulls in power production through the use of an electrolyser, fuel cell and hydrogen storage infrastructure. Other research efforts have been targeted towards determining the economic conditions that will render hydrogen production from renewable resources competitive against the fossil fuel intensive norm of SMR [7,9].

From all the renewable hydrogen production pathways encountered, the potential of hydrogen production exclusively from wind power, via electrolysis, has received substantial recognition globally [14–19]. Considering Life Cycle Assessment (LCA) studies carried out, hydrogen production from wind energy has been proven to be the most environmentally benign of all sustainable hydrogen production pathways [21,22]. This serves as an indication of the GHG emissions that can potentially be abated with the implementation of this technology. There is a scarcity of studies on the detailed techno-economic assessment of hydrogen produced from wind energy, as a feedstock to the chemical industry such as the oil sector and specifically for Western Canada.

In Canada, this area of hydrogen production exclusively from wind power has received minimal attention. Where wind energy is used for hydrogen production in the Canadian context, it is usually in partnership with another renewable resource [6,12,13] or in a mix of energy resources [3,4]. Furthermore, in most Canadian studies highlighted [3–8,10–13], hydrogen production is a secondary objective of the proposed system, hence the prevalent use of off-peak energy. The hydrogen produced is more often than not a raw-material for electricity generation, either to power fuel cell vehicles or electrical grids. The production of hydrogen exclusively from a single renewable resource in Canada, for a target market other than the auto-mobile or power generation industry - is relatively unexplored; with the work carried out by Sarkar and Kumar (2009 & 2010) [9,20] on the production of bio-hydrogen being the exception found in current literature.

The study carried out by Sarkar and Kumar (2009 & 2010) [9,20] focuses on the utilisation of Western Canada's, and more specifically, the province of Alberta's biomass resource for hydrogen production. The target market of the authors was the oil sands, bitumen upgrading industry in Alberta. The oil sands industry in Alberta, Western Canada, is heavily reliant on hydrogen for upgrading bitumen to synthetic crude; with hydrogen demand for bitumen upgrading in Alberta alone expected to reach 3.1 million tonnes/yr by 2023 [7]. To put this into context, the hydrogen capacity in 2004 for Canada as a whole was 2.23 million tonnes/year [7]. Hence, the accelerating demand for hydrogen in oil sands industry becomes evident. The conventional means through which hydrogen is produced in Alberta is mostly by natural gas via SMR. The displacement of SMR with the use of biomass resources in Alberta was one of the key objectives of Sarkar and Kumar (2009 & 2010) [9,20]. However, the renewable energy resource in Alberta is not just limited to biomass, southern Alberta in particular has a considerable wind energy resource which can potentially be used to power hydrogen production. The cost of hydrogen production, potential mitigation of GHG emissions, and the production capacity that could be realised from the wind resource in Alberta are presently unknown. Thus, the qualification and quantification of the potential environmental and economic benefits of hydrogen production exclusively from wind power deserves research attention.

The need for this research is further reinforced, considering the growth of wind energy in Canada by virtue of installed capacity. Canada has experienced a seven-fold increase in wind capacity from 2004 to 2009, and at present Canada is placed 11th in the world in terms of installed wind power [23]. In addition, considering its rising GHG emissions which have risen 54.8% from 1990 to 2006 [23], it is very likely that the wind power capacity will experience further growth. Hence, the effective utilization of wind power not only to mitigate the use of fossil fuels in power generation, but to facilitate the emergence of a sustainable, environmentally friendly, hydrogen economy, which offers a compelling solution for GHG emissions, is warranted. This paper aims to reduce the scarcity of research into hydrogen production exclusively from wind power in Canada, by the development of a techno-economic model for hydrogen production in Pincher Creek, Alberta, from wind energy, via the electrolysis of water. The electrolysis of water for hydrogen production is a mature technology, which yields hydrogen of very high purity levels, as high as 99.9995% [17,24]. High purity hydrogen is desired by the bitumen upgrading industry for the conversion of bitumen to synthetic crude oil and other petroleum products [25–27].

The wind hydrogen plant proposed in this paper is centred around the expansion of an existing wind farm in Pincher Creek, Alberta, i.e. the summerview wind farm, which currently comprises of 38, 1.8 MW wind turbines with a total capacity of 68 MW [28]. The summerview wind farm was planned as a multiphase project, and as of February 2010 it underwent an expansion of its capacity (22 additional wind turbines with a power rating of 3 MW each) with the commissioning of the summerview 2 wind farm located adjacent to its predecessor [29]. This highlights the plausibility of a further expansion, with the added feature of hydrogen production. The expansion of an existing wind farm will enhance the economic feasibility of the proposed plant due the significant cost reductions that are expected to be realised. The purchase of land, grid connection costs, infrastructure costs such as accessible roads, and water pipelines will be reduced per unit output; facilitating a cost-effective, sustainable means of hydrogen production. The reduction in costs can potentially translate into a production price of hydrogen that is competitive with the norm in hydrogen production in Alberta i.e. steam methane reforming (SMR). The economic feasibility of the plant is consolidated further by the fact that the electricity generated from wind power would be sold to the grid in periods where power output falls short of the threshold required for hydrogen production. Also, in periods where excess wind energy is available during the operation of the electrolyser, this is also sold to the grid to augment revenue. This is in sharp contrast with the use of off-peak energy for hydrogen production in the aforementioned studies [3–8,10–13]. For the plant proposed in this paper, hydrogen production is the underlying primary objective of the plant; as opposed to being a supplementary plant objective in the case of the aforementioned studies [3–8,10–13].

A data intensive techno-economic model was used to assess the production cost of hydrogen from the plant, and the cost of hydrogen delivery to the bitumen upgrader is also accounted for. Furthermore, the environmental impact of the proposed plant considering life cycle GHG emissions involved in the production of hydrogen, as well as the delivery of hydrogen is addressed and quantified. The impact of sustainable energy incentives such as feed-in-tariffs (FIT) on the competitiveness of the production price of hydrogen and the carbon emissions mitigation cost are also

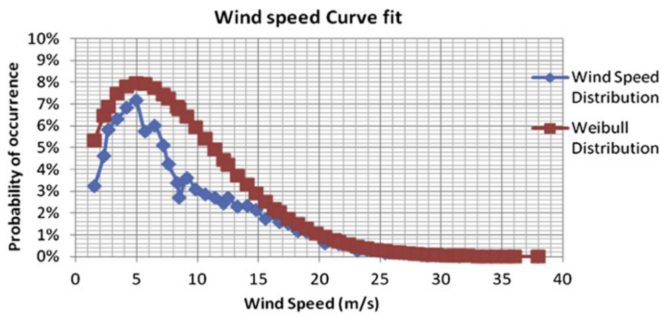

Fig. 1. Weibull curve fit for Pincher Creek Alberta.

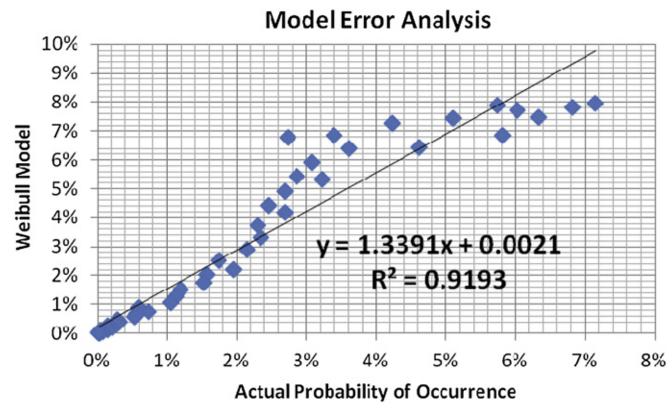

Fig. 2. Weibull model error analysis.

discussed and illustrated. Please note that all the cost data included in this study, are given in 2010 Canadian dollars.[1]

2. Methodology and scope

2.1. Quantification of wind energy potential

The average hourly wind speed variation for Pincher Creek, Alberta for 2009 was obtained from Environment Canada [30]. The wind speed data was corrected for a wind turbine hub height of 80 m using Eq. (1) [2] provided by Patel (1999) [31]. A probability density function known as the Weibull distribution (see Eq. (2)) was then used to characterise the annual variation of the wind speed [16–18]. Fig. 1 illustrates the Weibull curve fit with a shape factor k and scale factor c of 1.59 and 9.55, respectively.

A value for a of 0.15 was used to characterise the topography of the Pincher Creek municipality. This value of 0.15 corresponds to "foot high grass on level ground" [31]; which characterises the majority of the Pincher Creek municipality [32]. An error analysis of the Weibull model (see Fig. 2) verified the model's robustness at predicting the probability of occurrence of a given wind speed for the Pincher Creek plant location. Fig. 2 illustrates the probability predicted by the model in comparison to the actual probability of occurrence for each wind speed.

A Vestas V-90 1.8 MW wind turbine was selected for the proposed hydrogen production plant. This is the wind turbine manufacturer and power rating that is currently utilised at the summerview wind farm [28], and thus is assumed to be fit for purpose. Table 1 gives the specifications of the turbine as well as the calculated energy production. The wind turbine power curve is also provided by Vestas (see [33]).

The annual energy yield of the wind turbine, neglecting transmission losses, based on the variability of the wind resource, was calculated using Eq. (3) (in Appendix) taken from Zolezzi et al. [16]. Although transmission losses are not accounted for, a deduction of 8%–10% of the energy yield of the turbine will be a reasonable estimate if this was to be considered [16,34]. However, the percentage transmission line loss is dependent on the technology and length of the transmission lines [34]. The nominal amount of annual energy that would be produced (see Eq. (4) in Appendix) was then used to derive the capacity factor as shown in Table 1. The nominal energy amount depicts the ideal scenario where the wind speed is maintained at 12 m/s (which is the rated turbine wind speed) throughout the year.

The capacity factor was then deduced as the ratio of the annual energy yield to the nominal energy yield. It is important to reiterate that the capacity factor calculated here doesn't account for transmission line losses or wind turbine downtime due to maintenance e.g. de-icing of blades in winter. The results of the annual energy yield and capacity factor are comparable to those obtained by Zolezzi et al. [16] for a single Vestas 3 MW wind turbine, which is situated in a location with a more favourable wind resource [16]. Thus, the viability of Pincher Creek as the location for the plant was verified.

2.2. Hydrogen production pathway

2.2.1. Electrolyser selection

The electrolysis of water is the pathway for hydrogen production in this study. Water electrolysis is a well established mature technology that has been known for over 200 years [17,35,36]. Water electrolysis accounts for about 4% of global hydrogen production [35,36]. Hydrogen is produced via electrolysis by passing direct electric current through electrodes placed in water [24,37,38]; the water molecule is then split into its constituent elements of hydrogen (gas) and oxygen (gas) at the cathode and anode, respectively, via electrochemical reactions [37,38]. The reader is referred to the work carried out by Manage et al. [36], for details on the electrochemical reactions for the different electrolyser technologies. The current electrolyser (electrolysis) technologies that exist in literature can be categorised into three main types namely: alkaline electrolysers, proton exchange membrane (PEM) electrolysers, and high temperature electrolysis (HTE) [36,39–41].

The alkaline electrolyser usually has an aqueous solution of potassium hydroxide (KOH) and water as its electrolyte [36,37,39];

Table 1
Wind turbine specifications and energy production.

Wind turbine specification	Values	Source/Comments
Rated power (kW)	1800	[33]
Cut-in speed (m/s)	4	[33]
Cut-out speed (m/s)	25	[33]
Rotor diameter (m)	90	[33]
Hub height (m)	80	[33]
Energy production		
Annual energy yield (kWh)	7,684,807	No transmission line losses or maintenance downtime included
Annual nominal energy (kWh)	15,838,080	
Capacity factor	48.5%	

[1] A currency rate of US$1 = 1$CAD; £1 = 1.58 $CAD; and €1 = 1.4$CAD; was utilised for all cost data. An inflation rate of 2% was used to correct all cost sums into 2010 Canadian dollars.

[2] All equations are provided in the Appendix.

however the use of sodium hydroxide (NaOH) or sodium chloride (NaCl) with water is also a possibility [36,39]. The concentration of KOH in alkaline electrolysers is normally limited to the range of 20–30 wt% due to the competing factors of higher ionic conductivity (which increases efficiency) and corrosive effects, with increased concentration [24,36]. Alkaline electrolysers require the purification of the hydrogen produced [36], which can be achieved by in-built dehumidifiers/driers in the electrolyser units [37]. In addition, they also need cooling water to maintain an operating temperature in the range of about 70 °C–90 °C [14,36]. Alkaline electrolysers have efficiencies ranging from 64% to 85% (60.93–45.8 kWh/kg H_2 HHV of hydrogen) based on the values specified by several studies [14,36–38,42,43], with an operational life of 15 or 20 years in the case of certain studies [42,44]. However, the intermittency of power supply associated with renewable energy systems such as wind power, have adverse effects on the operational life of alkaline electrolysers [14,42]. In some cases the operational life of the electrolyser is reduced by a factor of 2 [42]. Hence, it is apparent that the degree of variability of the power source determines the operational life of this electrolyser. With regards to costs, the capital costs of alkaline electrolysers are relatively cheaper in comparison to other technologies [42,45], with no compromise on the purity of the hydrogen output. Furthermore, they are able to be produced in the megawatt scale [43,46,47], which allows for large scale hydrogen production in comparison to other electrolytic pathways - leading to reductions in the costs per unit of hydrogen produced.

The PEM electrolyser on the other hand has a solid polymer electrolyte, as opposed to an aqueous solution [36,39–41]. The need for purification of hydrogen is avoided with this technology, and the efficiency of this electrolyser has been shown to be superior to an alkaline electrolyser of the same capacity [42]. Furthermore, they are more robust in comparison to alkaline electrolysers with regards to handling intermittent power supply [14,42]. However, PEM electrolysers have higher capital costs [42,45]; with relatively short operational lives [42,44]. Furthermore, the capacity of PEM electrolysers is limited to the 10 kW range commercially [43], which inhibits large scale hydrogen productivity and the achievement of economies of scale as in the case of alkaline electrolysers.

High temperature electrolysis (HTE) is concerned with the electrolysis of steam as opposed to the use of water, with the use of solid-oxide electrolytic cells (SOEC) [36,39]. This technology is still at the demonstration stage with no example of industrial commercialisation from a survey carried out by Saur. G [45] .The premise of HTE is to reduce the electrical energy requirement of the electrolysis process by utilising the heat energy of steam in achieving the enthalpy of reaction needed to initiate the electrolysis reactions at the cathode and anode [24,39,48]. Elevated temperatures have been proven to provide increased ionic conductivity of the electrolyte, as well as the enhancement of the electrode surface kinetics [24,36,39,40]. Hence, this technology has the potential to attain increased electrolysis efficiency, and the production of hydrogen at a reduced cost. However, the process heat requirement raises questions about the compatibility of HTE with wind power, as the added costs of generating steam with wind energy is likely to be prohibitive. For the purposes of completeness, it is worth mentioning that Very High Temperature Nuclear Reactors (VHTR) are seen as the complementary power source for HTE by some authors [36,41]; as process heat and electricity can be supplied to HTE without entailing excessive costs and GHG emissions [39]. Even though this might be true, the technical demonstration of this technology is still pending [36,41]; as these very high temperature reactors are still in the pilot stage [36]. Also, the materials of the SOEC that are well suited for elevated temperatures are still the subject of research and development [36,48]. Lastly, the immense political pressure against the use of nuclear power worldwide, given the recent environmental impacts in Japan, presents a formidable hurdle for this technology.

Although the differing characteristics of the available electrolyser technologies have been appreciated above, a single factor greatly influences the choice of electrolyser technology. The choice of electrolyser to be utilised in the proposed plant is heavily influenced by the scale of the electrolyser hydrogen flow rate. There are two principal reasons for this. Firstly, the capital cost ($/kW) of the electrolyser decreases significantly with an increase in the production capacity [37,49–52]; facilitating the achievement of economies of scale. Secondly, the maximisation of production capacity decreases the cost of hydrogen per unit output. However, it is important to stress that the maximisation of the size of the electrolyser is not infinitely favourable. The size of the electrolyser unit relative to the size of the wind turbine capacity plays a pivotal role in determining the capacity factor of the electrolyser [14,38]; which in turn affects the cost of hydrogen production. The importance of cost minimisation with hydrogen production from wind energy cannot be over-emphasized, as this is a major investment barrier especially in relation to the production cost of SMR.

As a result, alkaline electrolysers are the most suitable for the proposed plant; given the scale of their hydrogen flow rates, market availability, moderate efficiencies, and their relatively inexpensive capital costs. The selection of the size of the electrolyser to suit the 1.8 MW wind turbine for the plant requires careful consideration. As mentioned earlier, the principal factors that will determine the appropriate size of the electrolyser include the capital cost, hydrogen productivity and the electrolyser capacity factor. The size of the electrolyser also determines how much energy is sold to the grid, which, depending on the electricity selling price, can be a pivotal factor in minimising the cost of hydrogen production. Hence, it is evident that a multitude of competing factors exist in determining the optimum size of the electrolyser which will minimise production costs. Therefore, the optimum size of the electrolyser unit will be determined by considering a range of electrolyser sizes as shown in Table 2. The electrolysers considered were obtained from a detailed study carried out by Ivy J. (2004) [37].

The classification of the electrolysers into constant and variable flow rates (VFRs) was as a result of some electrolysers having a fixed hydrogen flow rate while others had a degree of flexibility in their flow rates. The flexibility in the flow rate of the VFRs translates into flexibility in the minimum power demanded for the operation of the electrolysers. Some authors have specified that the minimum operating limit in terms of the power demanded by alkaline electrolysers in general is about 25–50% of their power rating [46]. However, more advanced MW scale electrolysers have this minimum as low as 5% of their rated capacity [46]. Other authors have specified the idling mode power requirement of electrolysers to be between 21% and 29% of their rated power [45]. The importance of the minimum power requirement stems from the fact that the operation of alkaline electrolysers at very low loads presents increased flammability risks [14]. This is because at very low production rates i.e. low current densities, the rate of hydrogen and oxygen production may be lower than the rate at which these gases permeate through the electrolyte and mix with each other [14]. This could cause potentially hazardous conditions, considering the flammability limits of hydrogen in oxygen (4.6%–93.9%) [14].

Due to the wide range of the electrolyser minimum power requirement, for the purpose of consistency, the approach taken in this paper is to establish a relationship between the minimum hydrogen flow rate and minimum power demanded by a given electrolyser. All electrolysers considered in this paper have an energy requirement of 4.8 kWh/Nm^3 irrespective of their size or

Table 2
Electrolyser size range [37].

Flow classification	Electrolyser manufacturer/model	Min. H_2 flow rate (Nm^3/h)	Max. H_2 flow rate (Nm^3/h)	Energy requirement (kWh/Nm^3)	Size (kW)	H_2 pressure (bar)
Constant Flow Rate Electrolysers (CFR)	Norsk HPE 24	24	24	4.8[a]	115	17
	Norsk HPE 30	30	30	4.8[a]	144	17
	Norsk HPE 40	40	40	4.8[a]	192	17
	Norsk HPE 50	50	50	4.8[a]	240	17
	Norsk HPE 60	60	60	4.8[a]	288	17
Variable Flow Rate Electrolysers (VFR)	Stuart IMET 1000, 2 cell stack	16	30	4.8	144	26
	Stuart IMET 1000, 3 cell stack	31	45	4.8	216	26
	Norsk Hydro Atmospheric Type No. 5010 (5150 Amp DC)	0[b]	50	4.8	240	1
	Stuart IMET 1000 6 cell stack	0[b]	90	4.8	360	26
	Norsk Hydro Atmospheric Type No. 5020 (5150 Amp DC)	50	150	4.8	720	1
	Norsk Hydro Atmospheric Type No. 5030 (5150 Amp DC)	150	300	4.8	1440	1

[a] Indicates the total hydrogen production system energy requirement specified by Norsk Hydro [37].
[b] A minimum flow rate of 1 Nm^3/h was utilised in the techno-economic model (see section 4.1).

manufacturer. This translates into a power requirement of 4.8 kW per Nm^3/h for a given electrolyser. As a result, the minimum electrolyser flow rate was used to derive the minimum power requirement for each electrolyser considered. In addition, the respective hydrogen output pressure of each electrolyser was also accounted for with regards to the energy consumed for the compression of hydrogen to the required delivery pressure (see section 4.2).

2.2.2. Quantification of hydrogen production

The amount of hydrogen to be produced is based on the smallest scale configuration of the proposed plant, which comprises of a single wind turbine and electrolyser unit along with other plant auxiliaries as depicted in Fig. 3. Hydrogen storage is considered to be beyond the scope of this paper, and is a subject of future research. The production of hydrogen is governed by the energy produced by the wind turbine and the minimum and maximum

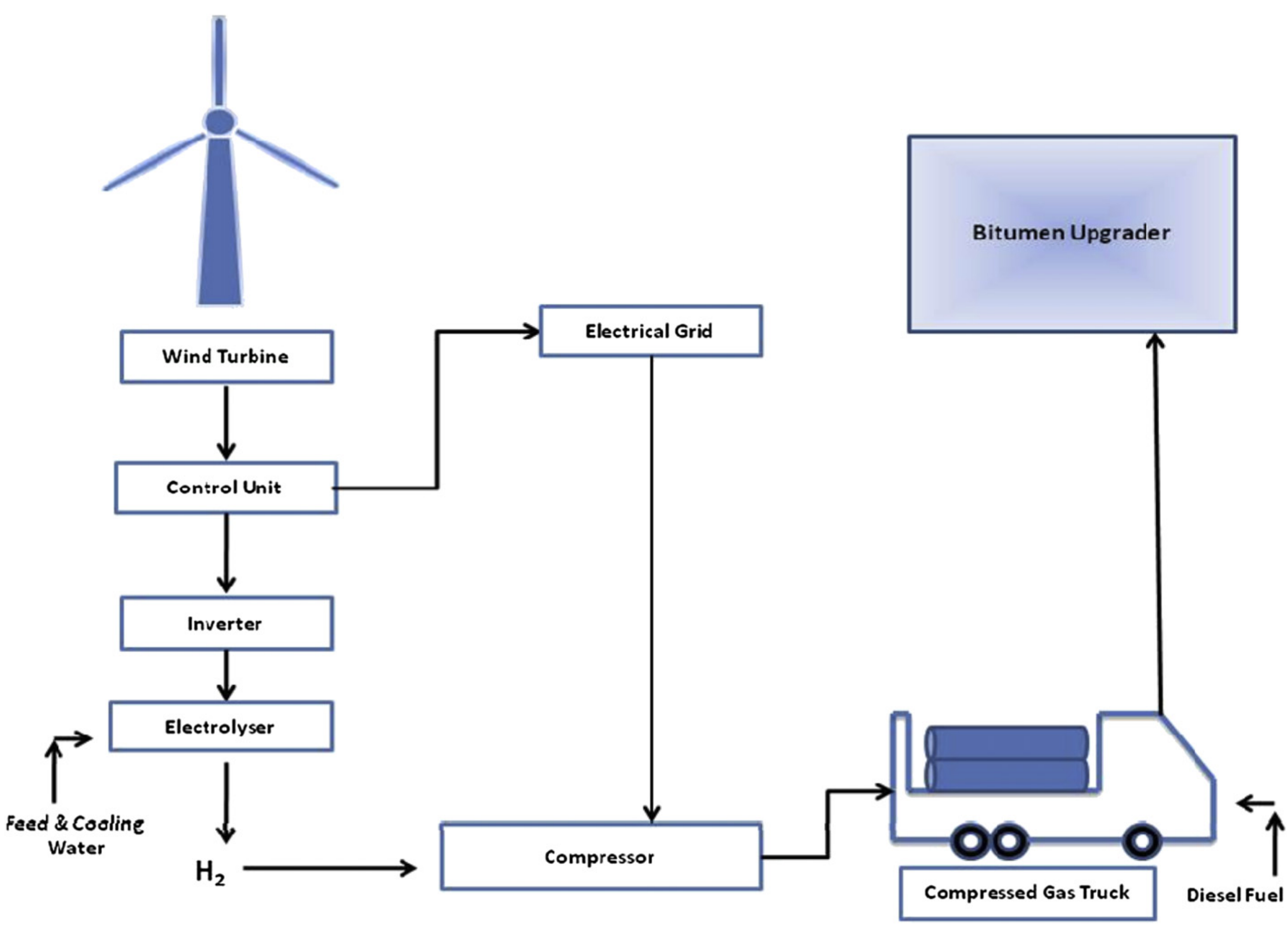

Fig. 3. Hydrogen production system.

power requirements of the electrolyser. Furthermore, the hydrogen flow rate range of the electrolyser unit in question is another determining factor for hydrogen production. As mentioned earlier, different electrolyser units were considered to ascertain the optimum size of the electrolyser which would lead to minimised hydrogen production costs.

Using the annual average hourly wind speed data [30], the allocation of the energy produced by the wind turbine either for hydrogen production and/or the sale of electricity to the grid is governed by the energy management flow chart shown in Fig. 4. The flow chart allows for the calculation of the amount of hydrogen produced from the plant and/or the amount of energy sold to the grid for each hour of the year. The summation of the hourly hydrogen production for the entire year yields the annual hydrogen production. The annual amount of energy sold to the grid is calculated in identical fashion.

An electrolyser efficiency of 73% (based on HHV of H_2) i.e. 4.8 kWh/Nm^3 energy requirement and an inverter efficiency of 95% [14,53] were utilised in the techno-economic model. However, some authors indicated that in practice the efficiency of the inverter will fluctuate depending on the power range [14,53]. Inverters are likely to have low efficiencies at low loads, and attain efficiencies of 90–95% at low to medium loads and medium to high loads [53].

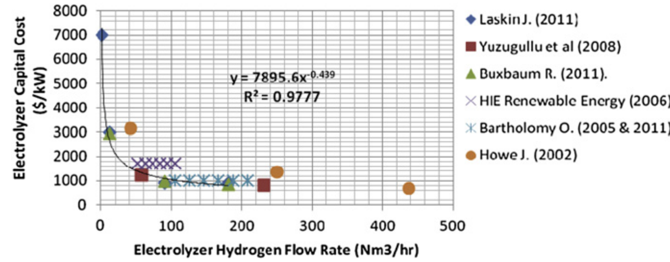

Fig. 5. Electrolyser capital cost model. Notes: An electrolyser conversion factor of 4.8 kW = 1 Nm^3/h (which is the equivalent of an electrolyser energy requirement of 4.8 kWh/Nm^3 i.e. 73% energy efficiency, based on H_2 HHV) was assumed for data provided by Buxbaum R. (2011) [50], Bartholomy O. (2005 & 2011) [44,54], HIE Renewable Energy (2006) [55], and Howe J. (2002) [52]. An electrolyser energy requirement of 4.8 kWh/Nm^3 was the predominant case among several manufacturers for a wide range of electrolyser sizes [37].

3. Cost estimation

3.1. Electrolyser capital cost

The capital cost of alkaline electrolysers reported by different studies varies a lot [36,38,42,44]. Various studies have utilised

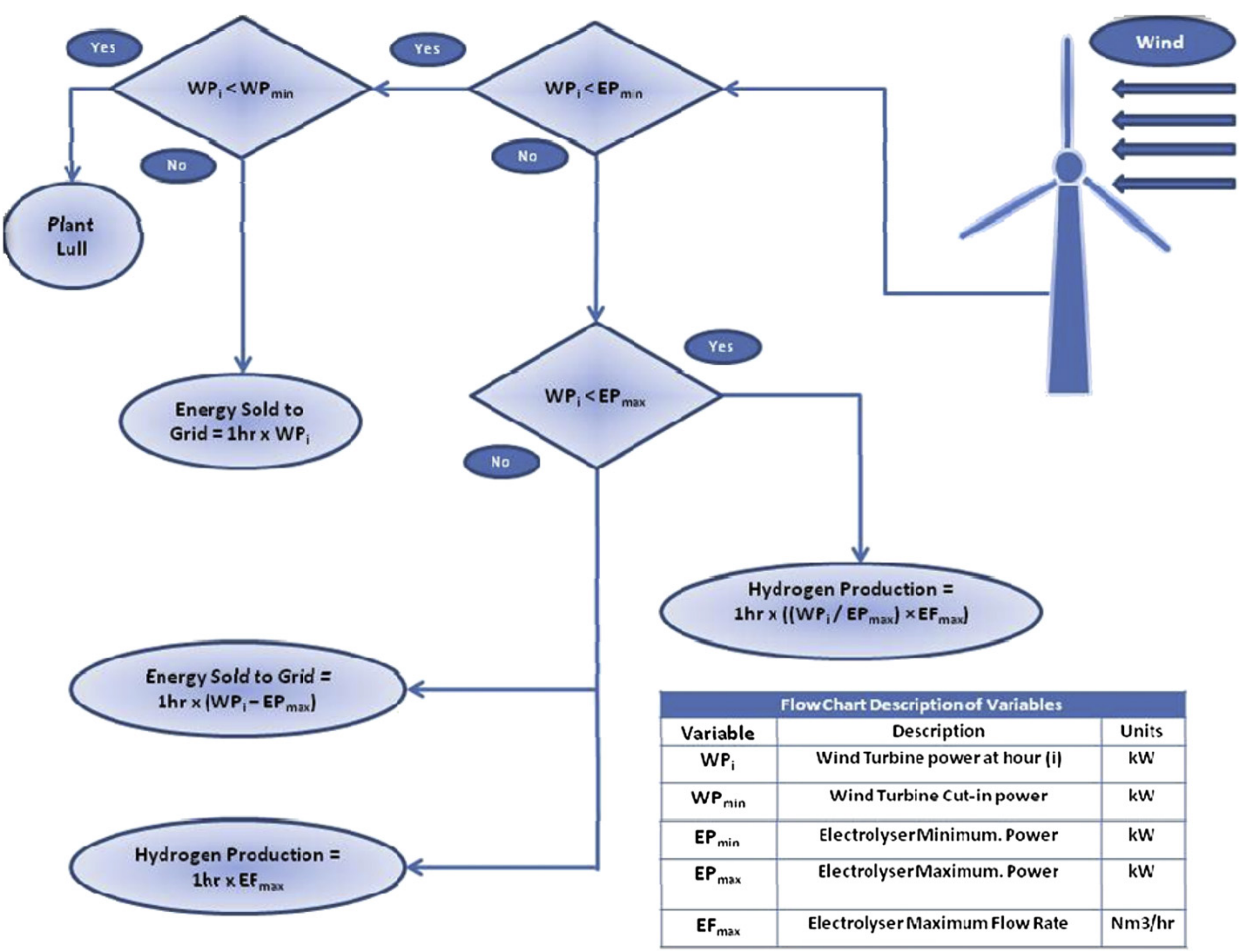

Fig. 4. Energy management flow chart.

Table 3
Wind turbine costs considered for cash flow and sensitivity analysis.

Wind turbine cost components	Values	Sources/Comments
Wind turbine capital cost ($/kW)	982	Derived as the from the average of values specified in [14,16,38,44]
Inverter capital cost ($) (17% of WT capital cost)	300,539	[17]
Control unit capital and installation cost ($) (10% of WT capital cost)	176,788	
Wind turbine labour and installation costs ($) (20% of WT capital cost)	353,575	[56]
Electrolyser labour and installation costs ($)	N/A: Function of electrolyser size	(4% of Electrolyser capital cost)
Wind turbine service life (yrs)	20	[17, 37, 44]
Electrolyser service life (yrs)	10	[37, 42]
Inverter service life (yrs)	10	[57]
Control unit service life (yrs)	10	

differing estimates of capital costs; with the specific electrolyser unit size (rated power/hydrogen flow rate) these costs correspond to being specified implicitly or left unspecified in the majority of cases. Hence, it became apparent that a scarcity of studies providing explicit and coherent data on the capital costs of alkaline electrolysers exists. As a result, a robust capital cost estimation model was developed in this study. In this light, the available data in literature as well as data obtained from industry experts were used to establish the model shown in Fig. 5. To present the data from the differing sources uniformly, some assumptions were adopted (see Fig. 5 notes).

3.2. Wind turbine and auxiliary units capital cost

The capital cost of wind turbine and the other plant equipment is provided in Table 3. The respective useful lives of plant equipment are also provided.

3.3. Operations and maintenance cost

The operations and maintenance costs for the plant are provided in Table 4 below. The electrolyser units require feed water and cooling water for their operation. Each electrolyser considered in the analysis is assumed to require 0.001 m^3/Nm^3 H_2 of feed water [16,58,59]; and the cooling water requirement is assumed to be 7 m^3/h [59]. The feed water in particular needs to have high purity to be fit for purpose for the electrolyser units. Ideally, the desalination costs of the feed water supplied, using a purification pathway such as reverse osmosis [16], would be included in the operations and maintenance costs. The energy requirement for reverse osmosis has been specified to be in the range of 5–9 kWh/m^3 [60]; while other authors have specified values as low as 2.4 kWh/m^3 for systems with energy recovery [61]. In addition, the investment and production cost of a plant producing 200 m^3/day of desalinised water via reverse osmosis has been specified as $500,000 and $3.25/$m^3$ respectively [60]. Some authors have provided the desalinised water production cost for much larger plant capacities (46,000 m^3/day) as $0.267/$m^3$ [61]. Considering the relatively minute amount of feed water required by the electrolysers, the desalination costs that would be incurred can be considered negligible, especially considering the 20 yr lifetime of the plant and the inexpensive production cost of desalinised water. The feed water requirement is highly disproportionate when compared to the amount of cooling water required. Hence, in this study the cooling water cost is assumed to account for water purification costs.

Table 4
Plant operation and maintenance costs.

Operations and maintenance costs	Values	Source/Comments
Wind Turbine O&M Cost (Years 1–6) ($/kWh/yr)	0.01	
Wind Turbine O&M Cost (Years 7–12) ($/kWh/yr)	0.03	
Wind Turbine O&M Cost (Years 13–20) ($/kWh/yr)	0.05	
Electrolyser O&M Cost ($/kW/yr)	17	[44]
Electrolyser Cell Stack Replacement Cost	N/A: Function of electrolyser size	30% of Electrolyser Capital cost [38]
Pincher Creek Water Cost ($/m3)	0.99	[64]

The general trend of operating and maintenance (O&M) cost for a wind turbine seems to increase every 4–6 years of its operational life, as substantiated by some authors [62,63]. The O&M cost appears to have a more volatile increase for smaller wind turbines in the kW range in comparison to larger wind turbines in the MW range [62,63]. The O&M cost for a 1.5 MW wind turbine has been shown to peak at $0.03/kWh in year 20 i.e. the final of its operational life [62]. However, a more conservative approach is adopted in this study mainly due to the severity of the winter in Alberta, which would entail the frequent removal of ice from wind turbine blades. The O&M cost for the wind turbine and other plant equipment is provided in Table 4.

4. Development of a Techno-economic model

4.1. Model data and economic factors

A data intensive, spread-sheet based, techno-economic model was developed to ascertain the production cost of hydrogen as well as the delivery cost. The techno-economic model incorporates the Weibull model, the plant energy management system, and a discounted cash flow analysis, to yield the respective costs aforementioned. The hydrogen production and delivery costs for the electrolyser range considered in this study (see Table 2) are calculated independently, with the summation of both costs yielding the total cost of hydrogen. A MARR of 10% was assumed in the model along with an inflation rate of 2%. The investment cost of the plant is serviced by 100% equity; the construction period for the commissioning of the plant is estimated at one year, with a plant lifetime of 20 years.

The base case selling price of electricity from the plant to the grid was considered to be equivalent to the average cost of electricity from the grid in Alberta i.e. $0.07/kWh [9]. In practice, the selling price will be quite volatile, and dependent on the grid demand and supply, time of day, seasons etc. The impact of the selling price of electricity on the production cost is examined in section 5.3. Furthermore, the effect of energy policy in minimising hydrogen production costs is examined with the concept of feed-in-tariffs (FIT). The province of Ontario in Canada, compensates power generation companies using wind energy for electricity production with $0.13/kWh produced [65]. For illustrative purposes, a scenario is evaluated when this policy is assumed to be in effect in Alberta, and the impact on the production cost of hydrogen is demonstrated in section 5.2.

4.2. Hydrogen delivery cost

The low volumetric energy density of hydrogen at standard conditions presents a challenge with regards to its reliable and

Table 5
Data for the gas compressed truck.

Compressed gas truck data	Values	Comments/sources
Transportation distance (km)	453	[67]
Tube Trailer Nominal Capacity ($kg\ H_2$/Truck)	300	[66]
Tube Trailer Net Capacity ($kg\ H_2$/Truck)	243.75	[66]. See equation (5)
Bitumen Upgrader delivery pressure (bar)	50	(rounded up) [9]
Tube trailer maximum pressure (bar)	160	[66]
Tube trailer minimum pressure (bar)	30	[66]
Tube trailer capital cost ($)	165,612	[66]
Undercarriage capital costs ($)	66,245	[66]
Truck cab capital costs ($)	99,367	[66]
Tube trailer O & M costs ($) (5% of capital cost)	8682	[66]
Truck cab O & M costs ($) (5% of capital cost)	5209	[66]
Plant production to upgrader delivery lead time (h)	24	
Labor hours per truck driver (h/day)	12	
Truck driver wage ($/h)	22.76	[68]
Truck availability (h/day)	24	Specified value
Truck fuel economy (km/gallon)	9.66	[66]
Diesel fuel price ($/gallon)	3.05	[69]
Truck average speed (km/h)	50	[66]
Hydrogen pick up/drop off time (h)	1	[66]
Average delivery time to upgrader (h)	9.06	
Truck cab lifetime (yrs)	5	[66]
Tube trailer lifetime (yrs)	20	[66]
Undercarriage lifetime (yrs)	10	
Variable non-fuel O&M (1% of total capital)	3647	[66]
Fixed operating costs (5% of total capital)	18233	[66]

economical transport [66]. As a result, the means by which hydrogen is delivered to the consumer is primarily a function of the rate of hydrogen production and the transport distance [66]. Depending on these two factors, three predominant hydrogen transmission modes are employed in practice: compressed (tube trailer) gas trucks, liquefied (cryogenic) hydrogen trucks, and hydrogen pipelines [66]. For low production rates ($<600\ kg\ H_2$/day) compressed gas trucks are used, for moderate rates ($600\ kg\ H_2$/day $<$ flow rate $<2400\ kg\ H_2$/day) cryogenic trucks are utilised, and for flow rates greater than $2400\ kg\ H_2$/day pipeline transmission is adopted [9].

The production rate of the proposed plant is less than $600\ kg\ H_2$/day for all electrolyser sizes considered (see Table 8). As a result, compressed gas trucks will be the pathway for hydrogen delivery. The required raw materials and machinery for compressed gas truck hydrogen delivery has been investigated extensively by Yang and Ogden (2007) [66]. The data for the compressed gas truck, compressor, and the annualised cost for hydrogen delivery are presented in Tables 5, 6, and 7 respectively. The bitumen upgrader is assumed to be located in the industrial heartland of Edmonton, Alberta, located north of Pincher creek (see Fig. 6). Furthermore, the electricity used to power the compressor is to be purchased from the grid with a rate of $0.07/kWh [9].

Table 6
Data for the compressor.

Compressor Data	Values	Comments/sources
Compressor capacity (kW)	10	[66]
Compressor capital cost ($)	16,561	[66]
Compressor electricity source	Grid	
Grid electricity charge ($/kWh)	0.07	[9]
Compressor O & M costs ($) (4% of capital cost)	695	[66]
Compressor life time (yrs)	7	
Compressor isentropic efficiency	65%	[70]
Compressor inlet temperature	25 °C	
Number of compression stages	2	

Table 7
Annualised delivery costs of the plant.

Annualized hydrogen delivery costs	Values	Source/Comments
Discount rate (%)	12.2	Accounts for 2% inflation
Capital recovery factor for compressor ($/yr)	3652	See Eq. (6)
Capital recovery factor for tube trailer ($/yr)	22,450	See Eq. (6)
Capital recovery factor for under carriage ($/yr)	11,820	See Eq. (6)
Capital recovery factor truck cab ($/yr)	27,702	See Eq. (6)
Total annualized capital costs ($/yr)	65,625	

It is important to point out that the number of trucks required for the plant varies depending on the hydrogen flow rate i.e. $kg\ H_2$/day. The compressed gas truck has a fixed capacity; and coupled with the delivery time constraint of 24 h (see Table 5), only a single trip (to and fro) to the bitumen upgrader will prove practical. Thus, when the hydrogen flow rate ($kg\ H_2$/day) from the plant exceeds the capacity of a single truck, an additional truck is required, and so on and so forth.[3] Hence, the number of trucks required for the electrolyser units considered will differ and affect delivery costs. Furthermore, the number of drivers required will be determined by the number of trucks needed. For a single truck, two drivers are required; and for two trucks four drivers are required. Each driver is responsible for a single one way journey to the upgrader (see Table 5).

The energy consumed by the compressor is dependent on the hydrogen output pressure yielded by each electrolyser considered (see Table 2). The hydrogen produced by all the electrolyser units considered needs to be compressed to the same delivery pressure of 50 bar [9]. Thus, the lower the output pressure of the electrolyser, the higher the energy consumed, leading to increased costs. A detailed study carried out by Ruth et al. [70] provided an equation of the compressor energy consumption which was adopted in this study (See Eq. (7)).

5. Results and discussion

5.1. Electrolyser performance

As shown in Table 8, for the CFRs, the least plant energy consumption is achieved for an electrolyser size of 240 kW (50 Nm^3/h). For the VFRs, this is achieved at a size of 360 kW (90 Nm^3/h). It is important to stress that all the electrolyser units have the same conversion efficiency; hence, the plant energy consumption, which is an energy efficiency index on its own, is a function of the power rating of the electrolyser and its flow rate. As a result, the two electrolyser sizes aforementioned represent the optimum size for each electrolyser classification (i.e. constant and variable flow) in relation to the 1.8 MW wind turbine. These two

[3] This trend remains true as long as the average hydrogen flow rate of the plant is less than $600\ kg\ H_2$/day. For flow rates greater than $600\ kg\ H_2$/day, another hydrogen delivery mode will be considered.

Table 8
Productivity and performance of the electrolyser range.

Flow Classification	Electrolyser Manufacturer/Model	Max. H_2 Flow rate (Nm3/h)	Size (kW)	H_2 Output (kg/yr)	Energy Used (kWh/yr)	Electricity Sold (kWh/yr)	Plant Energy Consumption (kWh/kg)	Capacity Factor
Constant Flow Rate Electrolysers (CFR)	Norsk HPE 24	24	115	13,839	1.14E + 06	6.55E + 06	82.30[a]	73%
	Norsk HPE 30	30	144	15,608	1.28E + 06	6.41E + 06	81.73[a]	66%
	Norsk HPE 40	40	192	20,810	1.67E + 06	6.01E + 06	80.37[a]	66%
	Norsk HPE 50	50	240	26,013	2.07E + 06	5.62E + 06	79.55[a]	66%
	Norsk HPE 60	60	288	25,654	2.04E + 06	5.64E + 06	79.60[a]	54%
Variable Flow Rate Electrolysers (VFR)	Stuart IMET 1000, 2 cell stack	30	144	17,293	1.40E + 06	6.28E + 06	81.20[a]	73%
	Stuart IMET 1000, 3 cell stack	45	216	23,411	1.87E + 06	5.81E + 06	79.91[a]	66%
	Norsk Hydro Atmospheric Type No. 5010 (5150 Amp DC)	50	240	28,418	2.25E + 06	5.43E + 06	79.27[a]	72%
	Stuart IMET 1000 6 cell stack	90	360	47,352	3.10E + 06	4.59E + 06	65.36[a]	67%
	Norsk Hydro Atmospheric Type No. 5020 (5150 Amp DC)	150	720	65,313	5.07E + 06	2.62E + 06	77.58[a]	55%
	Norsk Hydro Atmospheric Type No. 5030 (5150 Amp DC)	300	1440	81,001	6.26E + 06	1.42E + 06	77.33[a]	34%

[a] The plant energy consumption is independent of the respective electrolyser energy requirement. All electrolyser considered have an energy requirement of 4.8 kWh/Nm^3 see (Table 2).

electrolyser sizes translate into the minimum hydrogen production cost as seen in Figs. 7 and 8 respectively.

The results from Table 8 also show that for the same sized electrolyser (kW) and the same maximum hydrogen flow rate (e.g. Norsk HPE 50 and Norsk Hydro Atmospheric Type No. 5010 (5150 Amp DC)), the variable flow rate electrolyser has a lower plant energy consumption and a higher capacity factor compared to the constant flow rate electrolysers. This is quite intuitive, as the VFRs will be in operation for longer periods of the year due to their flexibility in flow rates and power requirements. Thus it becomes apparent that the VFRs are more likely to be used in practice due to their superior performance.

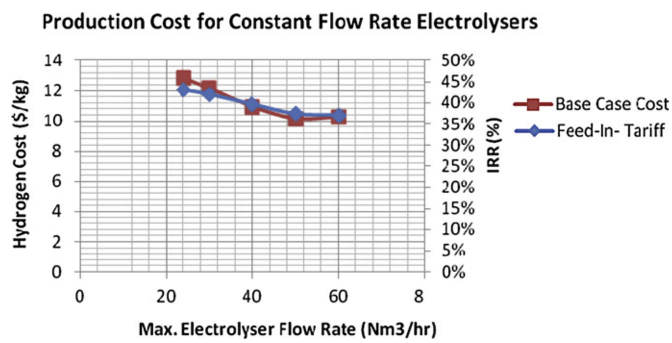

Fig. 7. Hydrogen production cost for constant flow rate electrolysers.

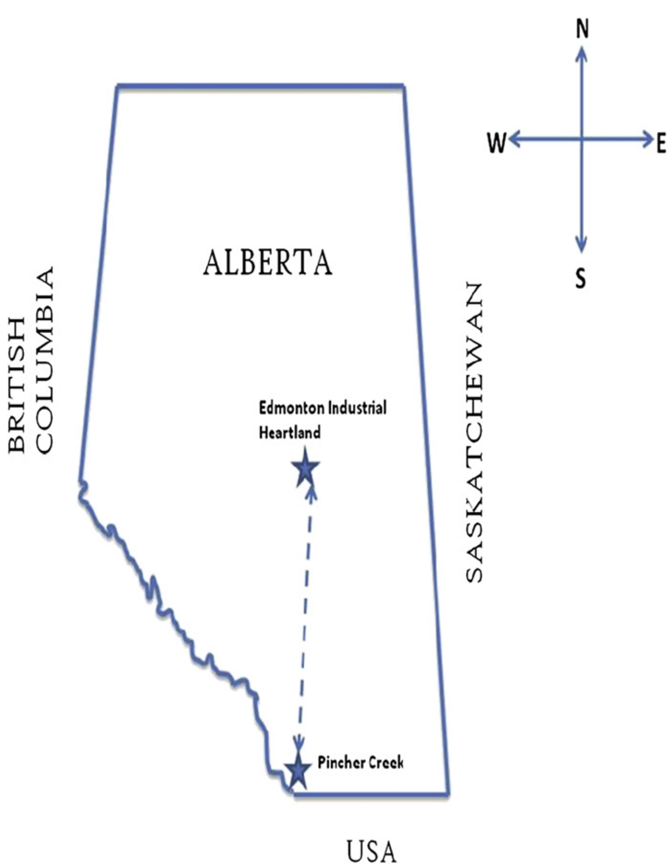

Fig. 6. Wind Hydrogen Plant and Bitumen Upgrader Geographical Location.

The ratio of the amount of energy sold to the grid and the amount of energy used for hydrogen production was the subject of optimisation by Levene J. [38] for the case of a grid connected wind/hydrogen plant. It was concluded that a ratio of 1.4 yielded the minimum hydrogen production cost. For this study, the optimum sized VFR yields a ratio of 1.48 which further consolidates its position as the 'best fit' for the wind turbine with respect to production cost.

5.2. Hydrogen production cost

The hydrogen production cost for the constant and variable flow rate electrolysers are given in Figs. 7 and 8. As shown in the Figures, the minimum hydrogen production price occurs at the respective

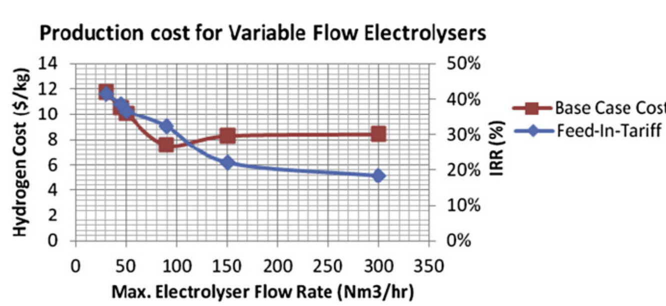

Fig. 8. Hydrogen production cost for variable flow rate electrolysers.

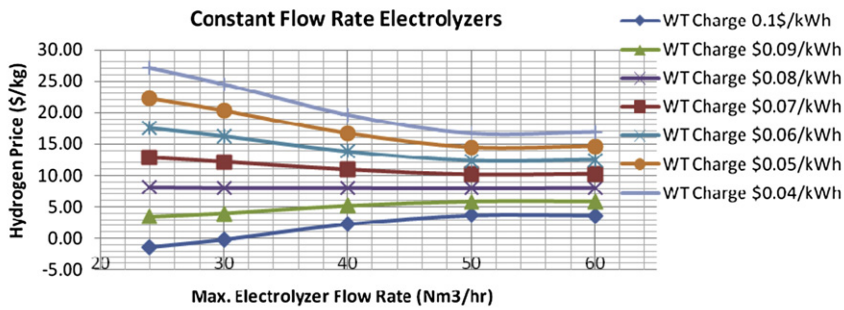

Fig. 9. Wind turbine charge sensitivity on hydrogen production cost for constant flow electrolysers. Negative price value indicates that the plant has a surplus amount of revenue from hydrogen production (at a MARR of 10% and the corresponding wind turbine charge), which can be used to mitigate other costs.

optimum sizes of 50 and 90 Nm^3/h. In both Figures the hydrogen production cost falls with an increase in the electrolyser size (at base case economic conditions) until it reaches a minimum at the electrolyser sizes aforementioned, and then rises.

The impact of the $0.13/kWh feed-in-tariff is reflected in the increased IRR for each hydrogen price. To put the data into context, it is worth re-iterating that the MARR for the plant was 10%. Thus, it can be seen in Figs. 7 and 8 that the FIT greatly improves the profitability of the plant. With regards to the production cost of SMR, the FIT will facilitate an equivalent hydrogen production cost of $0.96/kg H_2 with an IRR of 24% from the plant. The SMR production cost of $0.96/kg H_2 is for a plant with a hydrogen flow rate of 427 tonnes H_2/day and a natural gas price of $5/GJ [9,20].

5.3. Sensitivities

As mentioned earlier, the selling price of electricity (WT charge) is pivotal in determining the production cost of hydrogen from the plant. Thus, the scrutiny of the wind turbine electricity charge of the plant on the production price is warranted. Figs. 9 and 10 show the sensitivity of the hydrogen production cost in relation to the wind turbine (WT) charge.

For the constant flow rate electrolysers, the WT charge greatly influences the production cost for all electrolyser sizes. For a WT charge above $0.08/kWh, the cost of hydrogen production increases as the electrolyser size increases. This is as a result of more energy being sold to the grid for the smaller electrolysers in comparison to larger ones (see Table 8). Hence, if the WT charge is high enough, the revenue gained from the electricity sale offsets the low hydrogen productivity of the smaller electrolyser units, resulting in a cost-effective hydrogen production price.

However, at a WT charge less than $0.08/kWh, the gradient of the curve changes from being positive to negative. In this case, as the electrolyser size is increased the cost of hydrogen production decreases. This is due to the reduction of financial value of the energy sold to the grid; and as a consequence, the higher the hydrogen productivity the less the production price, which favours the larger electrolysers. The point of inflection of the curve from a positive to a negative gradient occurs at approximately $0.08/kWh. At this WT charge, a balance is struck between the two competing factors of hydrogen productivity and electricity sales for the larger and smaller electrolysers. This results in the hydrogen production cost being relatively independent of the size of the electrolyser units.

For the variable flow rate electrolysers, the sensitivity to the WT charge gradually weakens as the electrolyser size is increased. As seen in Fig. 10, for an electrolyser size greater that 250 Nm^3/h, the hydrogen production price is relatively independent of the WT charge. Similar to its constant flow rate counter-part, the point of inflection from a positive to negative gradient occurs at a WT charge of $0.08/kWh; and the smaller sized electrolysers are more cost effective at a WT charge rate above $0.08/kWh. Another shared characteristic is that for a WT charge less than $0.08/kWh, the larger electrolysers are more cost effective. The insensitivity of the variable flow rate electrolyser to the WT charge, for a size of 250 Nm^3/h or greater has considerable benefits. As mentioned earlier, the WT electricity charge will vary significantly depending on the time of day, season, grid demand, etc. Therefore the cost-effectiveness of the variable flow rate electrolyser is more robust, as it is relatively immune to significant fluctuations in the WT charge. Thus, the reliability of the variable flow rate electrolysers ($>=$ 250 Nm^3/h) reduces the degree of profitability risk associated with the plant.

Lastly, it is worth mentioning that the commercial value of the oxygen produced by the electrolysers is not accounted for in this study (subject of future research), and can possibly be a key sensitivity to the hydrogen production price. The potential revenue that can be derived from the sale of oxygen to industrial consumers can be considerable, and significantly depress the cost of hydrogen production as demonstrated by Kato et al. (2005) [71] and Saxe & Alvfors (2007) [72]. The application and economic assumptions utilised in both aforementioned studies differ to that incorporated in this paper, with both studies involving the supply of heat along with oxygen. However, it is worth mentioning that the hydrogen production cost for Kato et al. (2005) [71] was reported as[4]$6.45/kg H_2 ($0.58/Nm^3). The hydrogen specific production cost for Saxe & Alvfors (2007) [72] was reported as [4]$7.28/kg H_2 (€5.2/kg H_2). Both costs are comparable to the base case (VFR) minimum hydrogen production cost shown in section 5.2.

5.4. Delivery and total hydrogen cost

The hydrogen delivery cost as seen in Fig. 11 depreciates with an increase in the electrolyser size; illustrating the importance of scale in minimising delivery cost. However, because of the changes in the number of trucks required, there is a periodic rise in the delivery cost as the electrolyser size is increased. This is as a result of the capacity of the compressed gas delivery truck being exceeded (see section 4.2). The labour, truck fuel costs, and the cost of capital recovery are the principal contributors to the delivery costs. The labour cost in particular is the main contributor to costs and is especially high for smaller sized electrolysers. The O&M costs begin to have a significant impact on the cost for larger sized electrolysers.

With the consideration of the total costs i.e. the summation of production and delivery costs, the largest sized electrolyser

[4] Costs are likely to be higher in 2010 Canadian dollars, as the authors concerned have not explicitly indicated the financial year the costs correspond to.

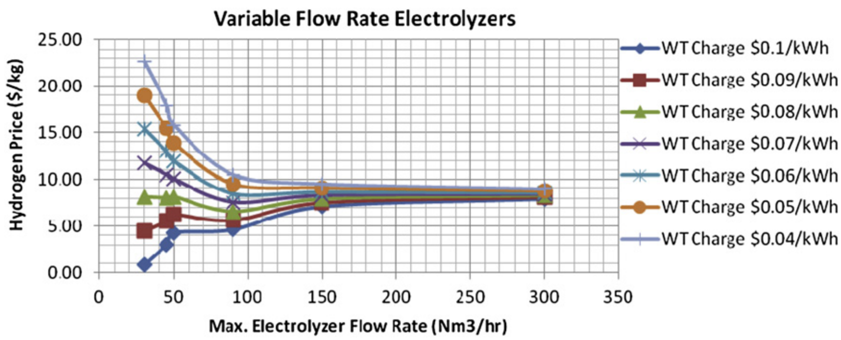

Fig. 10. Wind turbine charge sensitivity on hydrogen production cost for variable flow electrolysers.

considered (see Fig. 12) yields the minimum total cost; and is thus the overall optimal size for the wind turbine. The hydrogen delivery cost is a heavily dependent on the hydrogen flow rate of the electrolyser, while being independent of the amount of electricity sold to the grid. As a result, the minimisation of the delivery cost is strongly biased by the size of the electrolyser, and favours the larger units.

6. GHG life cycle emissions

The life cycle GHG emissions from the plant is an important issue to address, given that one of the key objectives of the plant is to consolidate the GHG mitigation efforts in Canada. In particular, the Government of Alberta plans to achieve a 200 mega tonne reduction in GHG emissions by 2050; which is the equivalent of a decrease of 14% from 2005 levels [73]. 18.5% of the 2050 GHG mitigation target is anticipated to be achieved via 'green' energy production [73]; thus the estimation of the GHG emissions mitigated by the plant is particularly pertinent. The life cycle GHG emissions from SMR has been reported by Utgikar and Thiesen (2006) [21] as about 12 kg CO_2 eq./kg H_2. This value is comparable with the SMR life cycle emissions data of 11.92, 13.7 and 11.88 kg CO_2 eq./kg H_2 as reported by Koroneos et al. (2004) [22], Dufour et al. (2009) [74], and Sarkar and Kumar (2010) [20], respectively. The studies aforementioned include the emissions associated with the production of natural gas, transportation, conversion to hydrogen, plant construction and decommissioning/disposal. The quantification of the GHG emissions from the plant will highlight the emissions mitigated in comparison to SMR, as well as the mitigation costs/carbon credits warranted.

A comprehensive life cycle CO_2 emissions analysis of electrolytic hydrogen production from wind power, as well as other renewable resources has been carried out by Koroneos et al. (2004) [22]. The

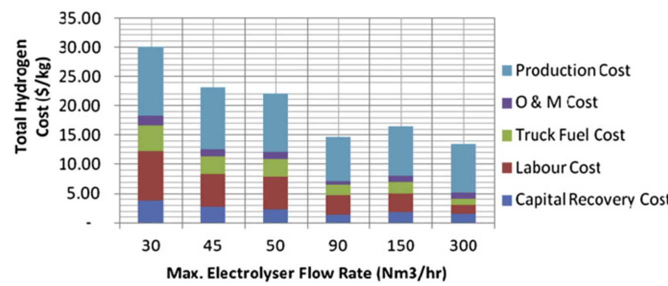

Fig. 12. Total hydrogen cost. The Total hydrogen cost shown here is for the variable flow rate electrolysers. See notes for Fig. 11.

system boundary of the life cycle analysis included the harnessing of the renewable energy resource, energy transport, production, and eventual use [22]. However, liquid hydrogen was the energy carrier used in the study, thus emissions concerned with hydrogen liquefaction were also accounted for [22]. Of All the renewable energy sources considered in the study, the CO_2 equivalent emissions from wind was the lowest with life cycle emissions of about 0.008 kg/MJ [21] which is the equivalent of 1.13 kg CO_2 eq./kg (based on HHV). Another study by Spath and Mann (2004) [75] gives the GHG emissions of electrolytic hydrogen from wind power as 0.97 kg CO_2 eq./kg H_2. About 78% of the GHG emissions stem from the construction and operation of the wind turbine, with 4% attributed to the electrolyser operation, and about 18% attributed to compression and storage (steel content of storage infrastructure primarily responsible for emissions) [75]. The use of iron (steel) for wind turbine manufacturing, limestone inputs for construction of the wind turbine foundation, and the use of coal for supplying the energy required for the production of steel

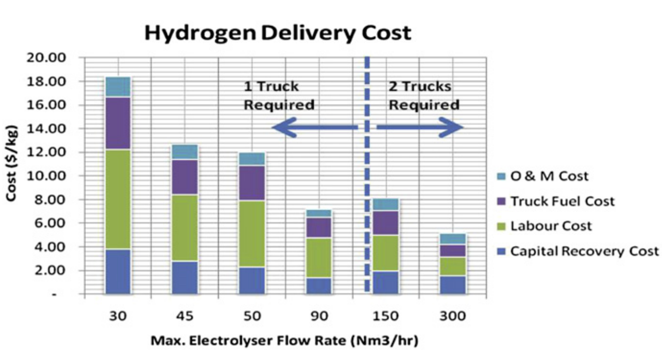

Fig. 11. Hydrogen delivery cost. The hydrogen delivery cost shown here is for the VFRs, due to their superior performance in comparison to constant flow rate electrolysers. The CFRs have significantly higher delivery costs.

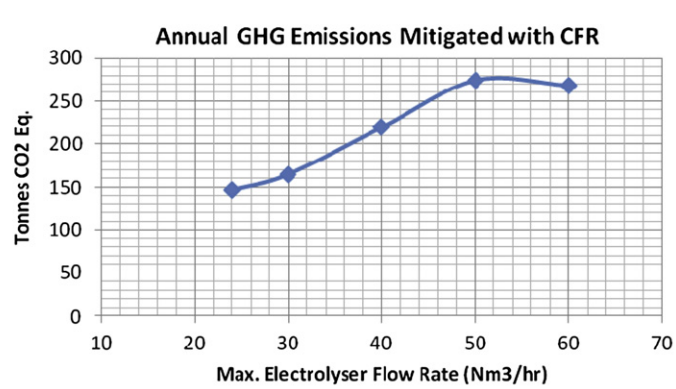

Fig. 13. Annual GHG emissions mitigated with the constant flow rate electrolysers.

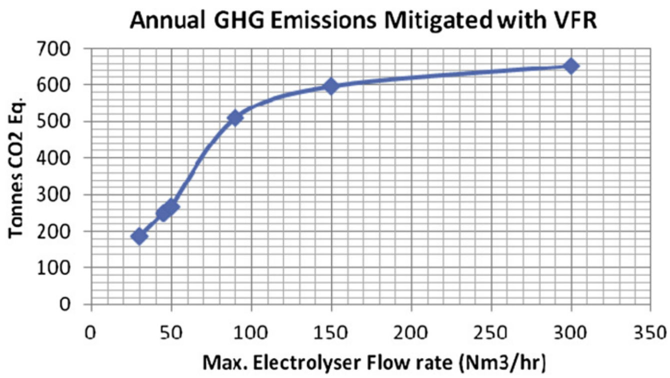

Fig. 14. Annual GHG emissions mitigated with the variable flow electrolysers.

and limestone are the principal emission culprits of the wind turbine [75].

For the GHG emissions of the plant for hydrogen production, the average value of GHG emissions presented by the authors aforementioned was utilized 1.05 kg CO_2 eq./kg H_2 [21,75]. The GHG emissions avoided with the use of the plant as opposed to SMR is illustrated in Figs. 13 and 14. The emissions mitigated increases rapidly with an increase in the electrolyser size, thus favouring the larger sized electrolysers. The values calculated also take the emissions associated with the energy supply for the compressor into consideration. The Alberta energy grid has a GHG emissions intensity of 0.88 kg CO_2 eq./kWh [76].

The life cycle CO_2 emissions of the plant would not be complete without the consideration of the delivery of hydrogen to the bitumen upgrader. The CO_2 emissions for the gas compression truck as a function of transport distance have been reported by Yang and Ogden (2007) [66]. The GHG emissions data assumes a low-carbon California electricity grid (0.3 kg CO_2/kWh) for the provision of electricity to the compressor; and accounts for the upstream GHG emissions of the diesel fuel together with the GHG emissions of the compression truck based on fuel economy and driving distance [66]. However, the GHG emissions associated with materials and equipment manufacture is not factored into the GHG emissions data [66]. For a transport distance of 453 km the CO_2 emissions with regards to the delivery of hydrogen is about 5.3 kg CO_2/kg H_2 [66]. Hence, it becomes apparent that the GHG emissions associated with the wind hydrogen plant are primarily due to the delivery of hydrogen to the bitumen upgrader. However, the GHG emissions avoided with respect to SMR still remains unchanged; as for the range of hydrogen flow rates from the plant, the same amount of hydrogen produced by SMR will have the same delivery mode and transport distance for an identical plant location. Considering the minimum hydrogen production cost of the plant of \$7.55/kg H_2 and an SMR production cost of \$0.96/kg H_2 [9,20], the carbon mitigation cost of the plant amounts to \$0.6/kg CO_2 eq.

7. Conclusions

This study developed a data intensive techno-economic model to determine the viability of the wind-hydrogen plant. The optimal electrolyser sizes for the 1.8 MW wind turbine considering hydrogen production only are 240 kW (50 Nm^3/h) and 360 kW (90 Nm^3/h) for the constant flow rate electrolyser (CFRs) and variable flow rate electrolyser (VFRs) respectively. The hydrogen production price for the CFRs becomes approximately independent of the electrolyser size at a wind turbine (WT) charge rate of \$0.08/kWh. On the other hand, the hydrogen production price of the VFRs becomes relatively independent of the WT charge for an electrolyser size greater or equal to 250 Nm^3/h. With the consideration of the total cost of hydrogen, the optimal size for the plant is the largest sized electrolyser considered which was 1440 kW (300 Nm^3/h). This same electrolyser size yields the maximum amount of GHG emissions mitigated. Energy policy in the form of a feed-In-tariff (\$0.13/kWh) has an immense effect on the profitability of the investment, and can facilitate an equivalent SMR hydrogen production cost with an attractive return of 24%. Finally, the commercialisation of the oxygen produced by the electrolyser can also enhance the competitiveness of the production price.

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Appendix

$$V_2 = V_1 \times \left(\frac{h_2}{h_1}\right)^{\alpha} \tag{1}$$

$$h(u) = \left(\frac{k}{c}\right)\left(\frac{u}{c}\right)^{k-1} e\left(-\frac{u}{c}\right)^{k} \text{for } 0 < u < \infty \tag{2}$$

$$\text{Annual Energy yield} = \sum_{i-a}^{b} h(u_i) \times \text{WT power}(u_i) \times 8760\text{h} \tag{3}$$

$$\text{Nominal Energy yield} = \text{Wind turbine Rated Power} \times 8760\text{h} \tag{4}$$

$$M_{\text{Net,Truck}} = M_{\text{Truck}}\left(1 - \frac{P_{\text{min,Truck}}}{P_{\text{max,Truck}}}\right) \tag{5}$$

$$\text{Capital Recovery Factor (CRF)} = P \times \left[(i \times (1+i)^n) \div ((1+i)^n - 1)\right] \tag{6}$$

$$CE_{\text{Annual}} = 8760 \frac{Q_{\text{avg}}}{\eta_{\text{isentropic}}} ZRT_1 N_{\text{ST}} \left(\frac{f}{f-1}\right)\left(\left(\frac{P_1}{P_2}\right)^{\frac{f-1}{fN_{\text{ST}}}} - 1\right) \tag{7}$$

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Nomenclature

Symbol, Quantity
α: ground surface coefficient
$\eta_{isentropic}$: isentropic compressor efficiency
a: wind turbine cut in speed
b: wind turbine cut out speed
c: scale parameter
CE_{Annual}: Annual compressor energy consumption
f: ratio of specific heats of hydrogen
h_1: height
h_2: height
h (u): wind speed probability
i: discount rate
k: shape parameter
M_{Truck}: nominal hydrogen capacity of truck
$M_{Net,\ Truck}$: net hydrogen capacity of truck
n: number of discounting periods
N_{ST}: number of compressor stages
P: present value
P_1: Compressor inlet pressure
P_2: Compressor outlet pressure
$P_{min,\ Truck}$: minimum truck pressure
$P_{max,\ Truck}$: maximum truck pressure
Q_{avg}: average plant hydrogen flow rate
R: hydrogen specific gas constant
T_1: Compressor inlet temperature
u: wind speed
V_1: wind speed at h_1
V_2: wind speed at h_2
WT power (u_i): wind turbine power at wind speed (u_i)