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Large scale hydrogen production from wind energy for the upgrading of bitumen from oil sands

Babatunde Olateju, Joshua Monds, Amit Kumar *

Department of Mechanical Engineering, University of Alberta, Edmonton, Alberta T6G 2G8, Canada

HIGHLIGHTS

- Techno-economic/simulation model developed for a large scale wind-hydrogen plant.
- Multitude of plant configurations considered for least cost H_2 production.
- Optimum electrolyzer unit size for minimum H_2 cost is 3496 kW (760Nm^3/h).
- Optimum electrolyzer farm size for minimum H_2 cost is 80 units.
- Large scale wind-based H_2 is not cost-competitive with natural gas-based H_2.

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ABSTRACT

There is considerable interest concerning sustainable, economically competitive and environmentally benign hydrogen production pathways. In this study, a large scale wind-hydrogen plant is assessed for the production of electrolytic hydrogen, for the servicing of the oil sands bitumen upgrading industry in Western Canada. The wind-hydrogen plant proposed has a capacity of 563 MW, along with the dual functionality of hydrogen production and electricity generation; with the delivery of hydrogen to the bitumen upgrader via pipeline. The research carried out involved the development of a data intensive techno-economic model in tandem with a simulation model of the plant. Several plant configurations were assessed to determine the optimum electrolyzer size and quantity – which would translate into the minimum hydrogen production cost (including delivery). The optimal plant configuration consists of 80 units of the 3496 kW (760 Nm^3/h) electrolyzer, which yields a minimum hydrogen production cost of \$8.43 and \$7.84/kg of H_2 with and without delivery. Therefore, currently, hydrogen production from wind energy remains uncompetitive relative to conventional fossil fuel hydrogen pathways.

1. Introduction

Hydrogen is an environmentally benign, versatile energy commodity; as it can be synthesized from a multitude of energy resources (both renewable and non-renewable) with multi-faceted end uses in the energy industry [1–5]. Considering the increasingly greenhouse gas (GHG) constrained global energy market, in the existing literature, hydrogen is often proposed as a GHG mitigation tool to ameliorate GHG intensive sectors – mainly by displacing the use of fossil fuels across industries such as transportation and power generation [6–11].

The utility of hydrogen as a feedstock in the chemical, and in particular, the oil refining industry, world over, is of significant importance [12–15]. This is because, aside from regulations on GHG emissions, the oil refining industry faces growing pressure to comply with increasingly stringent non-GHG environmental regulations – most notably, sulphur content in fuels [13–15]. To add to this challenge, heavier crude oil grades with higher sulphur and nitrogen content are becoming more widespread in the global energy market [13,15]. These aforementioned factors all result in a formidable rise in hydrogen demand, to facilitate compliance with fuel regulatory standards via hydrogen intensive hydrotreating and hydrocracking processes [13,15]

In Western Canada, hydrogen is a crucial feedstock to the oil sands industry as it is needed for the upgrading of bitumen to synthetic crude oil (SCO). Hydrogen demand in the bitumen upgrading industry is anticipated to reach 3.1 million tonnes/year in the industry by the year 2023 [16]; as oil sands production (a combination of SCO[1] and non-upgraded bitumen) is expected to rise from 1.6 million bpd in 2010 to 3 million bpd in 2020 [18]. In Alberta,

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* Corresponding author. Tel.: +1 780 492 7797; fax: +1 780 492 2200.
E-mail address: Amit.Kumar@ualberta.ca (A. Kumar).

[1] Synthetic Crude oil production in Alberta amounted to 126,400 m^3/day in 2010 [17].

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as is the case in much of the globe, hydrogen is predominantly produced via steam methane reforming (SMR) [12–14,19–21]; representing about 48% of global production [2]. However, SMR has a significant life cycle greenhouse gas (GHG) emissions footprint of about 11,000–13,000[2] tonnes of CO_2 equivalent per tonne of hydrogen produced [22–25]. Furthermore, the feedstock cost for SMR is highly variable; as natural gas prices are often difficult to predict, with high price volatility and sensitivity to market dynamics [17,26]. Apart from this, natural gas is a premium fossil fuel with a significant opportunity cost; thus, the continued reliance on SMR as the principal hydrogen production pathway in Western Canada raises questions about the sustainability of the bitumen upgrading industry, especially in the long-term.

As a result, there is considerable interest from industrial and governmental stakeholders concerning the production of hydrogen from conversion pathways which have low GHG footprints. Thus, research into the development of alternative hydrogen production pathways without compromising economic viability and maintaining a negligible GHG footprint is warranted; in order to facilitate the sustainable growth of the bitumen upgrading industry in North America, and other industries that exist within the hydrogen economy elsewhere.

Water-based electrolytic hydrogen production from wind energy is regarded to have the lowest[3] life cycle GHG emissions of all hydrogen pathways by a number of authors [23,24,27,28]. In addition, with the exception of hydropower, wind energy has the lowest levelised cost of electricity ($/kWh) amongst all renewable options in most jurisdictions around the world [29,30]; thus, a significant potential exists for extensive, cost-effective, GHG mitigation with this hydrogen pathway. Furthermore, extensive research pertaining to the techno-economic assessment of wind-hydrogen production systems has been carried out in a multitude of regions across the globe [31–35]. Contrastingly, the existing research addressing the techno-economic assessment of hydrogen production from wind energy in Western Canada is scarce; with the exception being a small scale grid connected wind-hydrogen production plant proposed by Olateju and Kumar [36]. The hydrogen production cost yielded by the aforementioned plant, including the cost of delivery amounts to $13.5/kg H_2 [36]; which renders the plant uncompetitive in comparison with the fossil fuel alternative by a relatively large margin. Thus, further research that addresses the techno-economic paradigm which will facilitate a positive shift in the cost-competiveness of wind-hydrogen systems (relative to the fossil fuel alternative) is warranted.

In this light, significant reductions in hydrogen production costs can be achieved with large scale wind hydrogen plants as substantiated by a number of authors [33,34,37–39]. Wind energy in Alberta has an estimated generating potential of about 64 GW [40]. However, as of 2012, wind power accounted for about 6% of the electricity generation capacity of the province [41]; with coal power being the predominant base load mitigating energy resource. Hence, due to the limited contribution of wind power to the provincial energy mix, the utilisation of the entire provincial wind energy resource for electrolytic hydrogen production is considered feasible.

An important point to note is that the methodology adopted in previous studies involving wind-hydrogen production often involves the modeling and characterization of the wind variability, via the use of a Weibull probability density function, to estimate energy, and consequently, hydrogen production [34,36,37,42–44]. This has limitations, and invariably, has a certain degree of error associated with it. Secondly, a fixed base case selling price of wind electricity is often utilized in the published literature for the estimation of the unit cost of hydrogen [33,34,36,38]; with sensitivity analysis often carried out to compensate for electricity price base case assumptions.

As a result, a key objective of this study is to circumvent the aforementioned modeling limitations by utilizing accurate, real time, wind power generation and electricity price data in the developed techno-economic and plant simulation model. This will in turn lead to decreased modeling uncertainty, and yield results which are more indicative of the 'real' hydrogen production cost in a particular jurisdiction. In addition, the research carried out aims to investigate the extent of economies of scale in wind-hydrogen systems, with the techno-economic assessment of a large scale wind-hydrogen plant in Western Canada. Apart from this, the determination of the optimum wind-hydrogen plant configuration which will result in a minimum hydrogen production cost is another objective. Therefore, this paper seeks to ascertain the optimum electrolyzer size and quantity which will facilitate the least hydrogen production cost (including delivery to a bitumen upgrader via hydrogen pipeline). All costs are in 2010 Canadian dollars[4], unless otherwise specified.

2. Methodology and scope

2.1. Site selection and energy logistics

The wind power generation capacity depends significantly on the available resource at a certain location. As shown in Table 1, as of 2009, the provincial wind generation capacity of the province totalled 563 MW [45,46]. Alberta's wind resource is concentrated in Southern Alberta, as reflected by the location of its wind farms illustrated in Fig. 1 [45]. For the wind-hydrogen plant proposed (see Fig. 2), the energy from the network of wind farms is channelled via the existing transmission line system to the summerview 1 wind farm in Pincher Creek; where the electrolyzer farm is located for hydrogen production. The electrolyser farm is situated at Pincher Creek due to the high density of wind farm locations in this area relative to other regions in Southern Alberta (see Fig. 1), as well as for comparative reasons with a previous study [36]. It is worth highlighting the fact that due to the geographically dispersed nature of the wind farm network on a localised level, the capacity factor of the electrolyzer farm has the potential to be significantly enhanced. This is regarded as a more efficient and pragmatic alternative to the option of having electrolyzer farms situated at each wind farm location, where the capacity factor of the electrolyzers are reduced due to the fact that they are constrained to the productivity of a single wind farm.

2.2. Simulation model for the wind-hydrogen plant

The wind-hydrogen plant proposed in this paper was modeled using the EXTEND 6 simulation package [47]. EXTEND 6 has the capacity for discrete and continuous event modeling [47]; with the latter being utilized for the purposes of this research. However, the modeling of the wind-hydrogen system can be achieved with several other simulation software; thus, the results presented here are independent of the simulation tool adopted. The principal model inputs involved comprised of the provincial hourly power generation and grid pool price, along with the alkaline electrolyzer specifications. The real time provincial hourly power generation and pool price data correspond to the year 2009, and was provided by the Alberta Electric Systems Operator (AESO) [48]. On the other

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[2] Value based on the higher heating value (HHV) of hydrogen (141 MJ/kg).

[3] Some authors have ranked this hydrogen pathway 3rd amongst all other options [2].

[4] Where necessary, an inflation rate of 2% has been used to convert all costs into 2010 $CAD. Furthermore, a currency rate of $1US = $1CAD is adopted in this paper.

Table 1
Grid-connected wind farm generation capacity in Alberta as of 2009 [45,46].

Wind Farm Name	Period of installation to 2009 year end capacity	# of Wind turbines	Wind turbine rated power (kW)	Wind farm capacity (MW)
Blue Trail Wind	2009	22	3000	66
Castle River #1	1997–2001	59	660	40
Cowley Ridge	1993–2001	57	375	38
		15	1300	
Enmax Taber	2007	37	2200	81
Kettles Hill	2006–2007	35	1800	63
McBride Lake	2001–2003	115	660	75
Sodergen Wind	2006	47	1500	68
Summerview 1	2002–2004	38	1800	68
Suncor Chin Chute	2006	20	1500	30
Suncor Magrath	2004	20	1500	30
Taylor Wind Farm	2004	9	375	4
			TOTAL	563

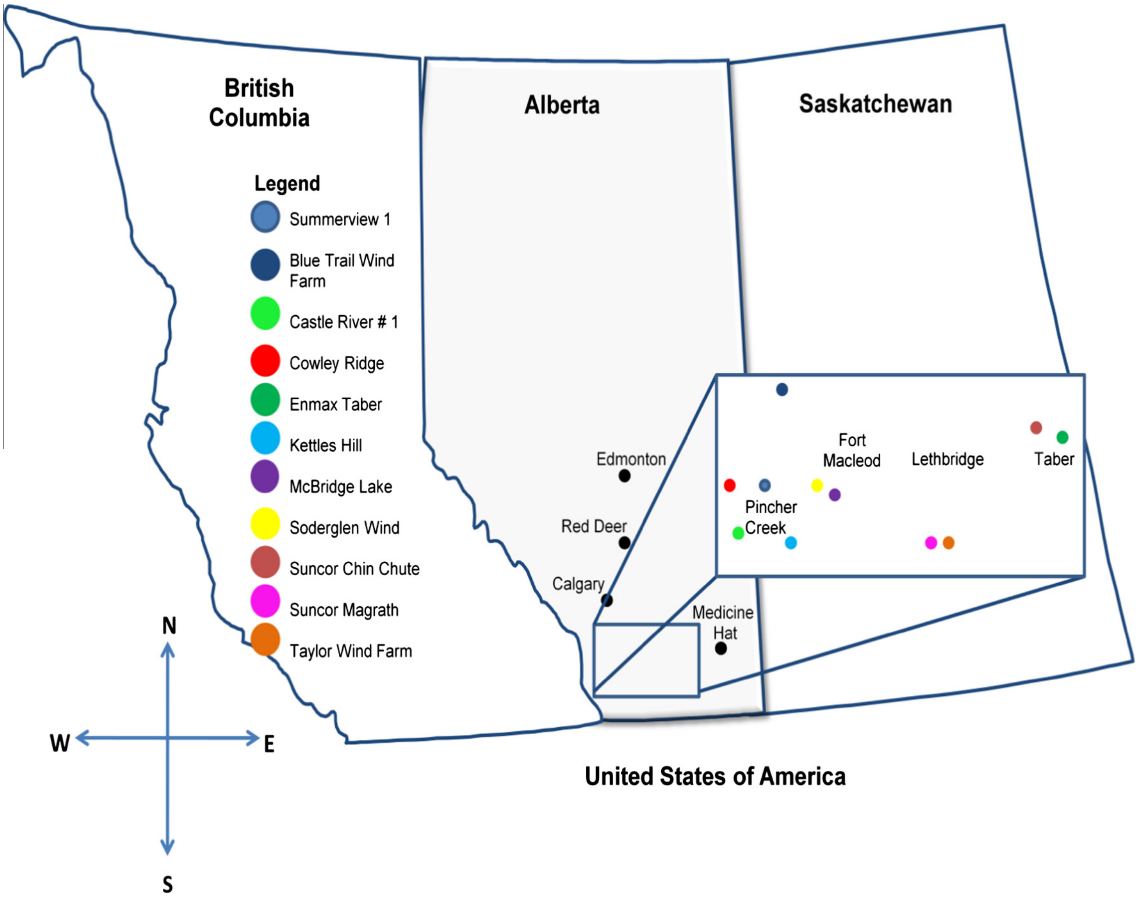

Fig. 1. Geographical depiction of grid-connected wind farm locations in Alberta (2009).

hand, the electrolyzer data input included the maximum and minimum power demand, hydrogen flow rate, and the number of electrolyzer units. A number of electrolyzer sizes were considered in the model (see Table 2) along with different numbers of units. Each case considered was run as a simulation with a duration of 8760 h to yield the annual hydrogen flow rate as well as the annual electricity revenue. The quantification of the annual hydrogen flow rate and annual amount of electricity dispatched to the grid is given greater scrutiny in Section 2.4.

2.3. Electrolyzer selection

The current electrolyzer (electrolysis) technologies that exist in literature can be sub-divided into three main classes, namely: alkaline electrolyzers, proton exchange membrane (PEM) electrolyzers, and high temperature electrolysis (HTE) [36]. Relative to other electrolyzer technologies, alkaline electrolyzers are adopted in this study as a result of their superior technological maturity, large scale hydrogen flow rates and relatively inexpensive capital cost [36]. For a more detailed scrutiny of the aforementioned electrolyzer technologies, the reader is referred to the work by Olateju and Kumar [36].

The electrolyzers considered in this study along with their performance specifications are given in Table 2. It is important to note that the minimum electrolyzer power requirement for all electrolyzers, has been determined based on a proportional relationship between the maximum flow rate and maximum power demand (rated power) of the electrolyzer as shown in Eq.

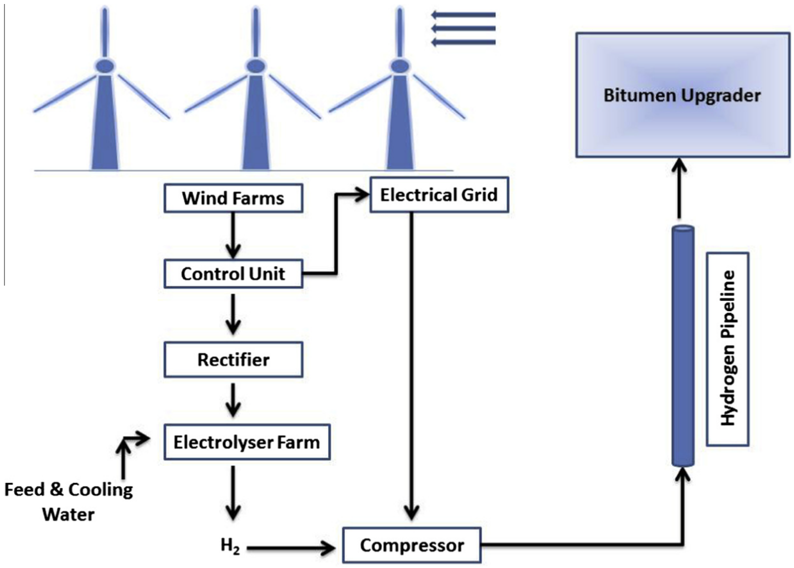

Fig. 2. Conceptual schematic of the wind-hydrogen plant.

Table 2
Electrolyzer size range [33,49].

Electrolyzer 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)	H_2 purity (%)
Norsk hydro atmospheric type No. 5010 (5150 Amp DC) [33]	0[a]	50	4.8[b]	240	1	99.9 ± 0.1
Norsk hydro atmospheric type No. 5020 (5150 Amp DC) [33]	50	150	4.8[b]	720	1	99.9 ± 0.1
Norsk hydro atmospheric type No. 5030 (5150 Amp DC) [33]	150	300	4.8[b]	1440	1	99.9 ± 0.1
Norsk hydro atmospheric type No. 5040 (4000 Amp DC) [33]	300	377	4.8[b]	1810	1	99.9 ± 0.1
Norsk hydro atmospheric type No. 5040 (5150 Amp DC) [33]	300	485	4.8[b]	2328	1	99.9 ± 0.1
Industrie Haute Technologie (IHT) Type S-556 [49]	190	760	4.9[b,c]	3496	30	99.9 ± 0.1

[a] A minimum flow rate of 1 Nm^3/h was utilized in this study.
[b] Indicates the hydrogen production systems level energy requirement specified by the manufacturer [33].
[c] Average value of the energy requirement range (4.6–5.2 kWh/Nm^3) indicated.

(1). The adoption of this approach is as a result of the energy requirement for all the electrolyzers being non-uniform.

$$EP_{min} = \frac{(EF_{min} \times EP_{max})}{(\eta \times EF_{max})} \quad (1)$$

2.4. Quantification of hydrogen production

The wind-hydrogen plant has a dual functionality of hydrogen production and electricity generation. Electricity generation is intended to enhance the plant's cost competiveness; as wind power will be sold to the grid in periods where power output falls short of the threshold required for hydrogen production. Furthermore, in the event where excess wind energy is available during hydrogen production, the simultaneous yield of hydrogen and electricity occurs, to consolidate the revenue generation capacity of the plant even further.

Using the average hourly wind power production data [48], the distribution 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 illustrated in Fig. 3. This flow chart, with the use of two decision tools ($WP_i \leqslant EP_{min}$ & $WP_i \leqslant EP_{max\ total}$), 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.

It is worth pointing out that, for reduced complexity, an implicit assumption is made with the energy management regime adopted in this study. The assumption is that the energy from the wind farms is distributed uniformly across all electrolyzers in a given plant configuration. This would imply that for an increased quantity of electrolyzers, it would be possible for a given electrolyzer unit to operate at a power level below EP_{min}.

In reality, it is more likely that power would be distributed within the electrolyzer farm in a non-uniform manner. For instance, one or more units may not be available at any given time due to maintenance, or a control system may switch units on or off given a set of safety considerations or the optimization of plant efficiency[5]. Thus, a plant operator may decide to run some units at

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[5] It is important to note that in practice, the energy requirement for a given electrolyzer will vary based on its operational load.

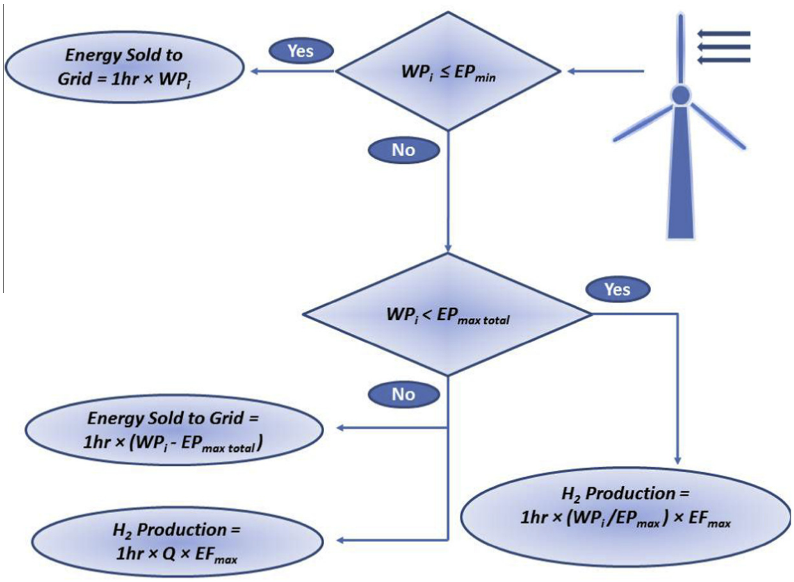

Fig. 3. Energy management flow chart.

full capacity while others remain idle; or all at half capacity, yet maintaining the same hydrogen output. Hence, it becomes apparent that irrespective of the energy allocation strategy adopted by a given plant operator managing the electrolyzer farm, the cumulative hydrogen production obtained per annum and subsequent electricity sold to the grid would be the same. Therefore, the energy management regime adopted here has no impact on the veracity of the results.

Lastly, an electrolyzer efficiency of 73% (based on HHV of H_2) i.e. 4.8 $/kWh energy requirement and a rectifier efficiency of 95% [50,51] were adopted in the EXTEND 6 simulations.

3. Cost estimation

3.1. Electrolyzer capital cost

An electrolyzer capital cost estimation model developed in an earlier study, which is based on data obtained from existing literature and industrial experts, was adopted to serve as a reliable estimate of costs [36]. The nature of the work carried out in the current study involves the capital cost estimation of a significant number of electrolyzer units with varying sizes. In reality, a degree of cost and labour efficiencies will likely be achieved, with the purchase of a large number of units from a particular vendor/manufacturer. However, this study takes a conservative approach, with the assumption that none of the aforementioned efficiencies are realized. Table 3 gives the further details on electrolyzer costs including installation, operating and maintenance (O&M) costs.

3.2. Wind turbine capital cost and auxiliary units costs

The wind turbine capital cost, O&M cost, along with costs and useful lives associated with auxiliary plant equipment and power electronics are provided in Table 3. Considering auxiliary plant costs in particular, it is important to note that the cost of purification of the feed water (via reverse osmosis) for the electrolyzers is miniature compared to the cooling water cost [36]. Thus, the latter has been assumed to account for the cost of purification.

3.3. Hydrogen pipeline costs

3.3.1. Hydrogen pipeline characterisation

For a hydrogen production flow rate that exceeds 2400 kg/day, pipeline transport of the hydrogen produced is regarded as the most cost effective means of delivery [55]. Thus, considering the large scale flow rate of the plant, for each plant configuration appraised from a techno-economic standpoint, the characterization of the appropriate pipeline is warranted[6]. The characterization of the hydrogen pipeline required the determination of two key pipeline parameters i.e. the pipeline diameter and pipeline length. The diameter of the hydrogen pipeline was calculated with the use of the Panhandle – B equation [56]. This equation was solved with a reverse engineering approach to obtain the required diameter for the plant's hydrogen flow rate. The estimate of the pipeline distance from Pincher Creek to the Industrial Heartland of Edmonton where the upgrader is located (see Fig. 1), is based on the driving distance between these two locations – about 450 km [36]. However, the distance of hydrogen delivery will vary depending on the jurisdiction in question.

3.3.2. Hydrogen pipeline capital cost

The hydrogen pipeline capital cost model utilized in this study is based on published literature [57] (see Fig. 4). The cost ascertained using this model was compared to other hydrogen pipeline capital cost models in the existing literature [58,59]. The difference in the pipeline capital cost between the model adopted in this paper and the models presented by Parker [58] and Johnson and Ogden [59] were 10% and 18%, respectively. As is the case with all pipelines, hydrogen pipeline capital costs will be highly site specific, and the consideration of the special pipeline seals required for hydrogen transport and the possible embrittlement of steel will play a significant role in determining costs [58]. In general, taking pipeline operation into account, an increased risk is associated with hydrogen pipelines relative to other industrial fluids (e.g.

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[6] Note that for plant configurations with a hydrogen flow rate less than 2400 kg/day, a hydrogen pipeline is not considered cost effective nor pragmatic [55]. However, the optimization of the delivery mode for each case is beyond the scope of this paper. Moreover, the flow rates encountered in the simulations run in this study are predominantly large scale (>2400 kg/day). Thus, a pipeline was sized specific to each simulation considered.

Table 3
Wind turbine and auxilliary plant costs.

Cost components	Values	Sources/comments
Wind turbine capital cost (\$/kW)	982	Derived from the average of values specified in [33,34,50,52]
Plant power electronics cost (\$/kW) (including rectifier and control unit cost)	35	Estimated relative to the cost specified for a 1 GW plant with no inverter [39]
Wind turbine labour and installation costs (\$/kW)	196	20% of WT capital cost [53]
Electrolyzer labour and installation costs (\$)	Function of electrolyzer size.	4% of electrolyzer capital cost [36]
Electrolyzer O&M cost (\$/kW/yr)	17	[52]
Electrolyzer cell stack replacement cost	Function of electrolyzer size.	30% of electrolyzer capital cost [33]
Wind turbine O&M cost (years 1–6) (\$/kWh/yr)	0.01	[36]
Wind turbine O&M cost (years 7–12) (\$/kWh/yr)	0.03	[36]
Wind turbine O&M cost (years 13–20) (\$/kWh/yr)	0.05	[36]
Pincher creek water cost (\$/m^3)	0.99	[36]
Wind turbine service life (yrs)	20	[33,52,31]
Electrolyzer service life (yrs)	10	[32,33]
Rectifier service life (yrs)	10	[54]
Control unit service life (yrs)	10	[36]

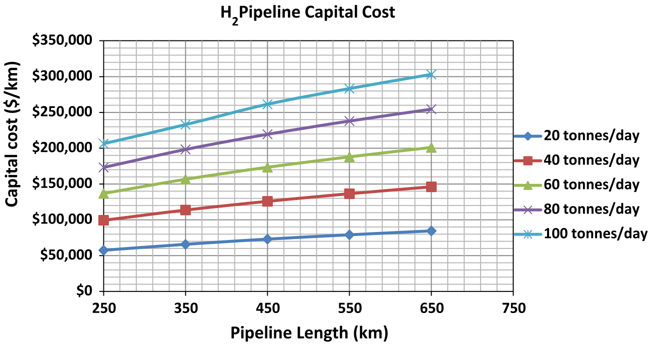

Fig. 4. Hydrogen pipeline capital cost.

CO_2 and natural gas). Thus, in practice, this elevated risk needs to be assessed and quantified; so as to be factored into the resulting cost estimates for improved accuracy. It is worth pointing out that in 2010, the Government of Alberta (GOA) approved the construction of a hydrogen pipeline by Air Products Inc. to transport hydrogen from the company's two production facilities to bitumen upgraders, refineries and chemical processors [60].

3.4. Hydrogen compressor cost

It is important to note that the desired delivery pressure of hydrogen by the bitumen upgrader is 50 bar [55]; hence, an elevated pipeline inlet pressure of 60 bar is utilized in this study. A compressor is required to raise the pressure of hydrogen to an elevated magnitude that would be conducive for pipeline transmission. The hydrogen compressor cost for each plant configuration is heavily dependent on the electrolyzer hydrogen output pressure; as this determines the pressure ratio that the compressor is subjected to. A two stage compressor with an efficiency of 70% and a specific capital cost \$970/kW is adopted in this paper [61]. A compressor was sized for each plant configuration considered, based on a model utilized in an earlier study [61].

3.5. Principal economic data and model assumptions

An IRR of 10% was utilized in the techno-economic model along with an inflation rate of 2%. The investment cost of the plant is serviced by 100% equity; and the construction period for the commissioning of the plant is estimated at one year, with a plant lifetime of 20 years [36]. In addition, the decommissioning cost of the plant is assumed to have a negligible present value and thus not considered. Furthermore, there would not be additional costs of land, transmission line costs, and other secondary plant set up costs, as there is existing wind farm infrastructure in Southern Alberta.

4. Results and discussion

4.1. Electrolyzer performance

A number of performance metrics used to assess the different electrolyzers considered in this study are provided in Table 4.

4.1.1. Electrolyzer farm size

As seen in Table 4, for the smaller electrolyzer units with a maximum H_2 flow rate in the range of 50–150 Nm^3/h, the number of units required to achieve the minimum hydrogen production cost is in the multiples of hundred. The practicality and challenges associated with the installation, energy management and monitoring of such a high number of units can prove to be prohibitive. Apart from this, the spatial footprint is an added hurdle, and more importantly, the hydrogen production cost achieved leaves more to be desired with regards to its competitiveness.

For the larger sized electrolyzers, although they suffer from reduced capacity factors in comparison to the smaller electrolyzers, the number of units warranted for the minimum hydrogen production cost is significantly lower and more pragmatic. Furthermore, the largest electrolyzer considered yields the minimum production cost of all simulations run.

4.1.2. Electrolyzer capacity factor

The variation of the electrolyzer capacity factor with the number of units is illustrated in Fig. 5. It can be seen in Fig. 5 that the negative slope of the capacity factor curve becomes increasingly steep as the electrolyzer size is increased. Thus, compared to the larger electrolyzers, the smaller electrolyzers maintain a higher capacity factor magnitude in general; and over a wider range of electrolyzer quantities. This is as a result of the undersized nature of the power demand of the smaller electrolyzers in comparison to the available power from the wind farms. To put the results into context, the aggregate capacity factor of the wind farms utilised in this study amounts to 30%. Hence, for cost competitiveness, the capacity factor of the electrolyzer farm must be greater than this value. This is reflected in the corresponding capacity factors for the respective minimum hydrogen production costs which range from 41% to 51% (see Table 4).

Table 4
Electrolyzer performance output.

Electrolyzer manufacturer/model	Max. H_2 flow rate (Nm^3/h)	Size (kW)	H_2 output (kg/day)	Energy sold to grid (kWh/yr)	Energy used for H_2 production (kWh/yr)	Number of electrolyzer units	Capacity factor (%)	Min. H_2 cost ($/kg)
Norsk hydro atmospheric type No. 5010 (5150)	50	240	43,640	2.37E + 08	1.23E + 09	800	51	13.88
Norsk hydro atmospheric type No. 5020 (5150)	150	720	46,523	1.56E + 08	1.31E + 09	300	48	10.82
Norsk hydro atmospheric type No. 5030 (5150)	300	1440	49,755	6.52E + 07	1.40E + 09	175	44	9.77
Norsk hydro atmospheric type No. 5040 (4000 Amp DC)	377	1810	50,878	3.33E + 07	1.43E + 09	150	42	9.54
Norsk hydro atmospheric type No. 5040 (5150 Amp DC)	485	2328	50,021	5.77E + 07	1.41E + 09	110	44	9.30
Industrie Haute Technologie (IHT) Type S -556	760	3496	53,475	2.32E + 07	1.44E + 09	80	41	8.43

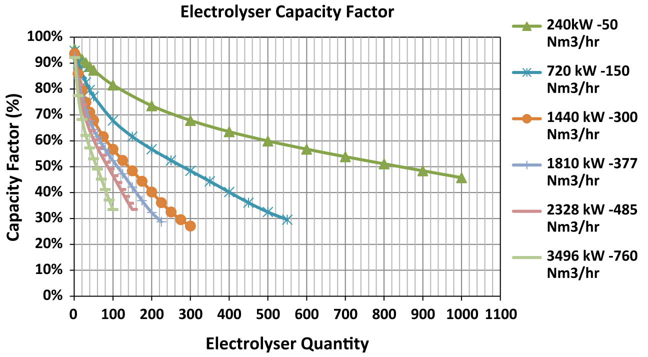

Fig. 5. Electrolyzer capacity factor.

Another important factor which influences the capacity factor of a given electrolyzer is the flow rate range, as this governs its operational flexibility. The wider the flow rate range, the higher the number of hours in which the electrolyzers are in operation; leading to a higher hydrogen productivity and capacity factor – which translates into a reduced production cost. This is exemplified by the largest electrolyzer unit (3496 kW (760 Nm^3/h)), as it possesses the widest flow rate range of all electrolyzers considered, hence yielding the minimum production cost.

However, it is worth pointing out that the use of varying combinations of electrolyzer unit sizes, has the potential to increase the capacity factor of the electrolyzer farm. For instance, in plant configurations where large scale electrolyzer units are used, the replacement of some units with smaller electrolyzers will facilitate a wider range of operation –which will likely translate into reduced production costs. Furthermore, in configurations where smaller electrolyzers are used, the substitution some units with larger ones has the potential to significantly reduce the number of units needed to achieve large scale hydrogen productivity; thereby decreasing the spatial footprint, the capital cost requirement ($) along with the complexity of managing a plant with a high volume of units.

4.1.3. Electricity production and revenue

The amount of energy dispatched to the grid is significantly higher for the smaller sized electrolyzers relative to their larger counterparts. This is quite intuitive as the smaller electrolyzers, for the same number of units, demand significantly less power for maximum hydrogen production; hence maintaining a high capacity factor whilst channeling significant amounts of energy to the grid for revenue (see Fig. 6). Furthermore, in similar fashion to the capacity factor curves, the electricity revenue curves have a negative slope which becomes increasingly steep as the electrolyzer size is increased (see Fig. 6).

However, as shown in Table 4, the increased revenue of the smaller electrolyers does not translate into a lower cost of hydrogen production. This is attributed to the fact that the increased revenue does not compensate for the increased capital cost requirement ($) of the smaller electrolyzers, as a result of the relatively high number of units required to achieve a hydrogen production flow rate in the same order of magnitude as larger electrolyzers. However, it is important to point out that in jurisdictions where wind generated electricity is sold to the grid at a premium, or where renewable energy incentives such as feed-in-tariffs (FIT) exist, the H_2 cost competitiveness of the smaller electrolyzers will be greatly enhanced. On another note, it is worth pointing out that another revenue generation scheme is the sale of the oxygen produced by the electrolyzers to an existing market.

4.2. Hydrogen production cost

The non-linear variation of the hydrogen production cost with electrolyzer size and quantity is provided in Fig. 7. The minimum cost achieved in the analysis carried out, with and without delivery, amounts to a cost of $8.43 and $7.84/kg of H_2 respectively; corresponding to 80 units of the 3496 kW (760 Nm^3/h) electrolyzer. The overarching trend is a decrease in the hydrogen production cost as the electrolyzer size is increased (see Fig. 7). Furthermore, all the production cost curves have a minimum value (see Table 4), after which the costs escalate with an increase in the number of electrolyzer units. This is due to the interrelated and competing forces of the electrolyzer capital cost, capacity factor, hydrogen productivity and grid electricity sales. The capital cost ($/kW),

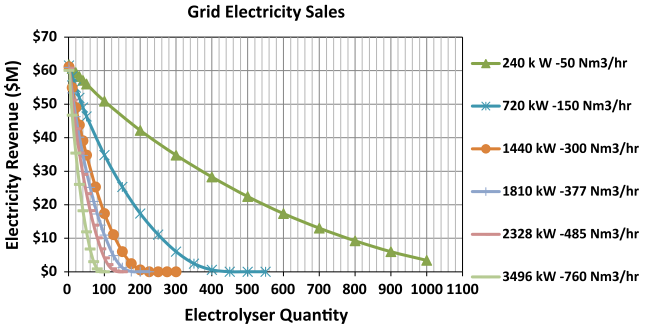

Fig. 6. Grid electricity sales.

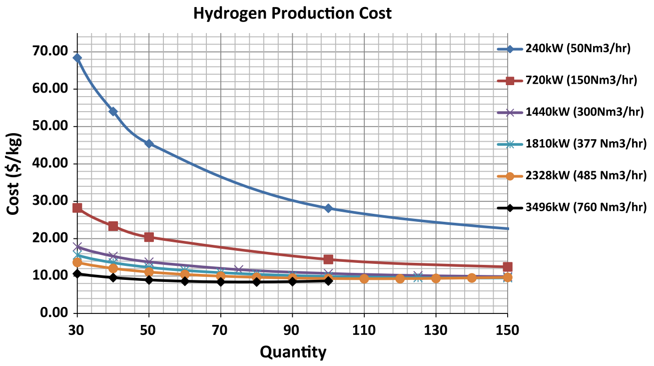

Fig. 7. Hydrogen production cost.

capacity factor and grid electricity sales, decrease as the electrolyzer size in increased; however, hydrogen productivity increases, with the opposite being true as the electrolyzer size is decreased. All the aforementioned parameters play a significant role in determining the hydrogen production cost. However, the most significant of all cost elements is the wind turbine capital cost which accounts for about 55% of the hydrogen production cost for the optimum electrolyzer size and number (i.e. 3496 kW (760 Nm^3/h) and 80 units). The sensitivity of the hydrogen production cost to the wind turbine capital cost is shown in Fig. 8. Note that the wind turbine capital cost estimate for a capacity of 563 MW is a constant value for all plant configurations considered.

Relative to previous work carried out on a small-scale wind hydrogen plant in Western Canada [36], significant economies of scale are apparent in this study; as the hydrogen production cost experiences a 37% decrease from $13.5/kg of H_2 to $8.43/kg of H_2. In comparison to previous studies on large scale wind hydrogen production [33,34,37–39], the cost of $8.43/kg of H_2 achieved in this study appears relatively high. However, the comparison of costs should be carried out with full consciousness of the underlying economic assumptions, quality of the wind resource, plant scale, rate of return and disparities pertaining to the methodologies and scope of the techno-economic assessment in the aforementioned studies. For instance, the work carried out by Levene [33] involves the assumption of a wind farm capacity factor of 40%, a fixed electricity price of $0.03/kWh, along with the inclusion of production tax credits; all of which amount to hydrogen production cost of $ 6.13/kg of H_2 for an IRR of 10%. Apart from this, the cost of hydrogen delivery is not accounted for in the study [33]. In other studies [34,39], the hydrogen production cost estimate of $2.48/kg of H_2 (2030 price forecast in US dollars, with 10% IRR [34]) and $2.98/kg of H_2 (for an equivalent H_2 pipeline length – i.e. 450 km) [39] have been provided. However, the estimate provided by some authors is based on a cost accounting methodology that does not consider a specified IRR; instead focusing on the capital recovery factor [39]. Moreover, the electrolyzer capital costs of $306/kW [34] and $330/kW [39] are heavily discounted in comparison to the capital costs adopted in this study. Furthermore, the wind resource utilized for the hydrogen plant has a capacity factor of 54% and 40% for Zolezzi et al. [34] and Leighty et al. [39] respectively, in comparison to the capacity factor of 30% in this study.

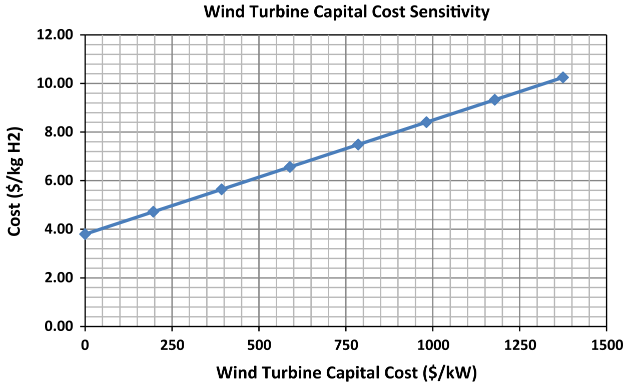

Fig. 8. Hydrogen production cost sensitivity to wind turbine capital cost.

5. Conclusion

From the techno-economic evaluation conducted, the minimum hydrogen production cost for a large scale wind-hydrogen plant of capacity 563 MW, as proposed in this study, amounts to $8.43 and $7.84/kg of H_2 with and without delivery to the bitumen upgrader respectively. In addition, the optimal plant configuration consists of 80 units of the 3496 kW (760 Nm^3/h) electrolyzer. Furthermore, from the results generated, it can be inferred that for hydrogen production from large scale wind-hydrogen plants, large scale (MW) electrolyzers with a wide flow rate/operating range are required to facilitate cost competitiveness.

The plant component with the most significant impact on production costs is the wind turbine capital cost. A reduced capital cost is likely to be achieved in the near future as wind energy continues to mature and pervade the energy markets around the globe. The near future also has the potential to introduce, in the form of energy policy, a significant cost penalty for GHG emissions which could introduce a competitive advantage for hydrogen production from wind energy. Furthermore, as practiced in some jurisdictions, renewable energy incentives such as feed-in-tariffs will enhance the cost-effectiveness of wind-hydrogen even further. As for present times, the wind-hydrogen pathway remains economically uncompetitive in comparison to the fossil fuel alternative i.e. SMR.

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