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A techno-economic assessment of large scale wind-hydrogen production with energy storage in Western Canada

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ABSTRACT

Hydrogen production via steam methane reforming (SMR) dominates the supply to refining complexes worldwide, resulting in significant greenhouse gas (GHG) emissions. There is a considerable demand for clean hydrogen pathways that are economically competitive with SMR. The development of a 563 MW integrated wind-hydrogen model with energy storage is proposed. The model utilizes real-time wind energy data to ascertain the optimal size of the electrolyser, the number of electrolyser units and the battery (energy storage) capacity that will yield a minimum hydrogen production cost, whilst functioning in a liberalized electricity market with dynamic prices. The optimal plant configuration consists of 81 units of a 3496 kW (760 Nm^3/hr) electrolyser and 360 MWh (60 units) of battery capacity. For the minimum hydrogen production cost determined (\$9.00//kg H_2), the wind farm accounts for 63% of this cost. Hence, if existing wind farm assets are used, such that the investment cost of building the wind-hydrogen plant does not include the wind farm costs, the hydrogen production cost is reduced to \$3.37/kg H_2. For a particular electrolyser-battery configuration, it was observed that the minimum hydrogen production cost occurs when their respective capacity factors are approximately equivalent. The benefits of energy storage are limited by the decrease in overall plant efficiency, which results from the use of the battery. For the techno-economic conditions considered in this paper, hydrogen production costs from wind powered electrolysis (\$3.37 to \$9.00/kg H_2) are uncompetitive with SMR/SMR-CCS (\$1.87 to \$2.60/kg H_2).

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Introduction

The production of hydrogen via steam methane reforming (SMR) in crude oil refining complexes is facing intense scrutiny [1–4]. Aside from regulations on greenhouse gas (GHG) emissions, the oil refining industry faces growing pressure to comply with increasingly stringent non-GHG environmental regulations – most notably, sulphur content in fuels [2–4]. Additionally, heavier crude oil grades with higher sulphur and nitrogen content are a growing portion of the global supply mix [2,4]. To facilitate compliance with fuel regulatory standards via hydrogen intensive hydrotreating and hydrocracking processes, the oil refining sector has experienced a formidable rise in hydrogen demand [2,4].

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Abbreviations

AC	Alternating Current
AESO	Alberta Electric System Operator
CCS	Carbon Capture and Sequestration
DC	Direct Current
DCF	Discounted Cash Flow
FUNNEL	Fundamental Engineering Principles Based Model
GHG	Greenhouse Gas
GW	Gigawatt
IRR	Internal Rate of Return
kW	Kilowatt
kWh	Kilowatt-hour
MW	Megawatt
MWh	Megawatt-hour
NREL	National Renewable Energy Laboratory
OEM	Original Equipment Manufacturing
O & M	Operating and Maintenance
PEM	Proton Exchange Membrane
HTE	High Temperature Electrolysis
SCO	Synthetic Crude Oil
SMR	Steam Methane Reforming

In Alberta, Western Canada, the bitumen upgrading industry has a considerable hydrogen demand for the production of synthetic crude oil (SCO); this need for hydrogen is expected to amount to 3.1 million tonnes/year by 2023 [5]. Steam-methane reforming is the single most prevalent pathway for hydrogen production; accounting of 48% of global supply [6]. While SMR is economically attractive, it produces a significant GHG emission footprint, i.e., in the range of 11,000–13,000 tonnes of CO_2 equivalent per tonne of hydrogen produced (based on HHV of H_2) [7–10]. Moreover, the industry-wide dominance of SMR as the hydrogen production pathway of choice creates significant economic exposure to natural gas prices; which although relatively low in recent times, have a history of significant price volatility (see Fig. 1). Hence, in an increasingly GHG constrained energy market where economic competitiveness is increasingly coupled to environmental stewardship and the social license to operate, an alternative environmentally benign H_2 pathway, which remains economically palatable, is desired in the bitumen upgrading industry.

Wind powered electrolytic (via water electrolysis) hydrogen production is considered to incur the lowest life-cycle GHG emissions of all hydrogen pathways, amongst a number of authors [8,9,11,12]. Furthermore, in the context of renewable energy pathways, with the exception of hydro-power, wind energy has the lowest levelized cost of electricity ($/kWh) in most jurisdictions around the world [13–15]. Thus, a promising opportunity exists for cost-efficient, environmental benign, hydrogen production and GHG mitigation with this pathway. In Alberta, wind energy has an estimated generating potential of about 64 GW [16]. As of 2014, wind power accounted for about 9% of the electricity generation capacity of the province [17]; with coal power serving as the dominant base load electricity supply. In order to evaluate the techno-economic prospects of large scale wind-hydrogen production in Alberta, the installed wind energy capacity as of 2009 (563 MW) is utilized for electrolytic hydrogen production in this paper. This is to say that the hydrogen production costs determined in this paper are specific to a wind energy capacity of 563 MW, unless otherwise specified.

Previous studies that address hydrogen production from renewable and non-renewable studies in Alberta have been conducted [6,7,18–26]; in particular, Olateju, Monds & Kumar (2014) [6] as well as Olateju & Kumar (2011) [25], have addressed grid-connected wind-hydrogen systems at small and large plant scales. However, to the knowledge of the authors, no previous studies have addressed wind-hydrogen systems with the use of energy storage (battery energy storage) to ascertain the optimal plant configuration (minimum H_2 cost) for a given capacity of wind energy. More generally, the existing research regarding the techno-economic assessment of wind-hydrogen systems is quite extensive; with a multitude of modelling approaches, implicit and explicit assumptions and limitations therein. This paper aims to improve upon the limitations associated with the seemingly normative techno-economic modelling frameworks, widely adopted in the pertinent literature. Some of these modelling trends and their associated drawbacks are highlighted in the subsequent paragraphs vis-à-vis the methodology incorporated in this paper.

From an economic standpoint, the assessment of grid connected wind-hydrogen systems in existing studies often involves hydrogen production costs being ascertained using fixed/average electricity prices [25,27–30]. This modelling paradigm does not account for the dynamic pricing environment which is indicative of the increasingly liberalized electricity markets across the globe [31,32]. As such, the hydrogen production cost estimates that result can be limited in accuracy. The dynamic pricing environment facilitates opportunities to take advantage of peak/premium electricity prices; owing to the electricity price differential that exists, depending on the time of day (see Fig. 2). Premium electricity prices provide an opportunity to enhance the competiveness of wind-hydrogen systems. To take advantage of these prices however, dynamic energy storage is required. In this study, batteries (electrical energy storage) are used to realize differential pricing opportunities on the electrical grid, as opposed to a hydrogen storage[1]–fuel cell pathway utilized in previous research [27,33–36]. The use of hydrogen-fuel cell configurations incur a significant cost, and more importantly, a low round trip efficiency of about 25–30% [27,33–36]; this limits the added competitive advantage that can be harnessed from price differentials in a liberalized electricity market.

A common norm in the modelling of wind-hydrogen systems is the direct coupling of the electrolyser unit to the wind turbine, without intermediate energy storage [6,25,30,33,34,37,38]. By doing this, authors make the implicit assumption that the electrolyser units will perform at their

[1] In this paper, hydrogen demand variations are assumed to be negligible, hence, hydrogen storage when necessary, is facilitated through the use of a pipeline (see Section Wind-Hydrogen Plant Description); this is in line with the options for hydrogen storage highlighted in previous studies [15,88].

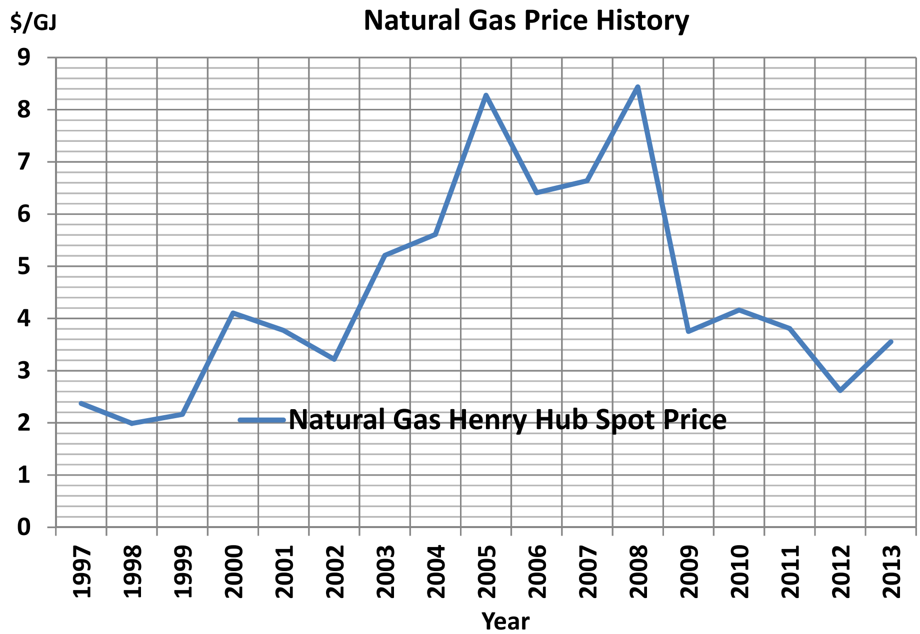

Fig. 1 – Historical natural gas price in Alberta 1997–2013 [45].

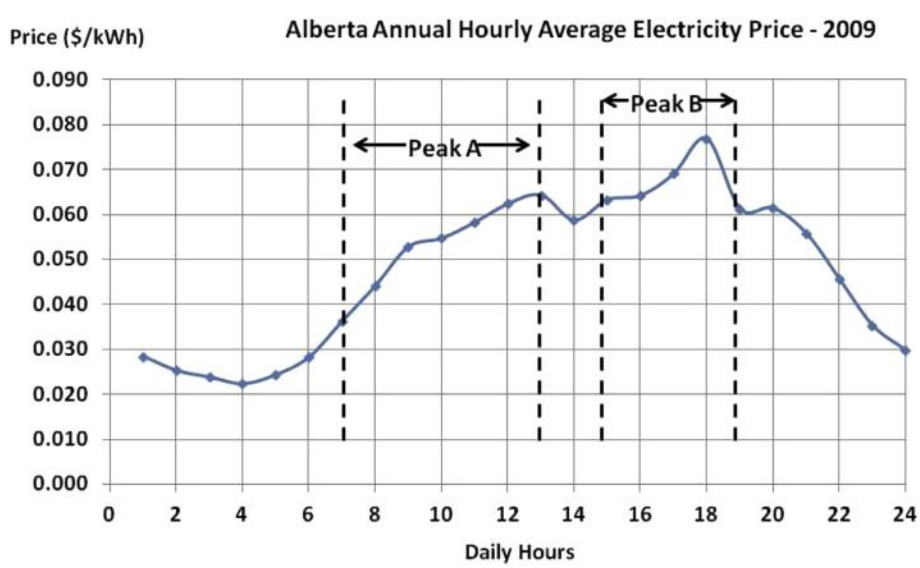

Fig. 2 – Alberta annual hourly average electricity (grid pool) price – 2009 [46].

nominal efficiencies, despite the perturbed and often transient nature of the power input – this is particularly pertinent to alkaline electrolysers [6,25,30,33,34,37,38]; other authors assumed a lower efficiency based on the intermittent nature of wind energy [6,20] – however, there is a degree of uncertainty with the efficiency value assumed. In practice, the variability of the wind energy input has an adverse effect on the nominal efficiency of the electrolyser as well as its operating life [30,39]. Therefore, without energy storage to smoothen the erratic profile of the wind energy input and dispense this energy in a more uniform fashion to the electrolyser, hydrogen production has a likelihood of being overestimated, with costs under-estimated. With this in mind, the wind-hydrogen model developed here addresses this issue, while providing a framework for the optimal sizing of the battery capacity (i.e. the capacity that yields a minimum H_2 cost) for a given electrolyser size.

Another pervasive modelling approach in the existing literature is the characterization of the wind variability, via the use of statistical methods, most notably, a Weibull probability density function - to estimate energy, and consequently, hydrogen production [25,34,37,38,40–42]. While the efficacy of the Weibull function in resolving the variability of the wind speed is not disputed, a certain degree of error is inherent in the estimation of the probability of occurrence of a given wind speed magnitude. This in turn, hinders the accuracy of the energy production estimates. Moreover, the Weibull function is limited in its ability to accurately resolve bimodal or multimodal wind distributions which arise from unique climatic conditions [43,44]. The model developed in this paper utilizes real time hourly wind energy generation data, thus its accuracy is not hindered by the limitations of the Weibull function.

Considering the foregoing, the principal objectives/contributions of this paper are as follows:

- The development of an integrated grid-connected wind-H_2 techno-economic model with energy storage, for the production of renewable hydrogen and estimation of costs, in a liberalized electricity market with dynamic prices.
- The development of an energy management algorithm for wind-H_2 plants with energy storage, which is a function of the wind turbine energy yield, hourly wholesale electricity price (pool price), electrolyser and battery performance specifications.
- The development of a techno-economic framework for the determination of the optimal electrolyser size, number of electrolyser units and energy storage capacity, which yields a minimum hydrogen production cost, for wind-hydrogen systems with energy storage.

The model has been developed such that its inputs are not constrained to a particular jurisdiction. For instance, variables that can be readily adjusted to suit various jurisdictional contexts (e.g. peak electricity price hours and the wind energy generation profile) are used in the model. In this paper, Alberta serves as the case study of choice; with the hydrogen produced being 'customized' to service the bitumen upgrading industry. There is a scarcity of integrated wind-hydrogen models which consider the full supply chain of hydrogen from production to delivery, whilst incorporating the modelling features aforementioned. By circumventing the limitations associated with previous modelling approaches, the hydrogen production cost estimates provided by the model in this article are more indicative of 'real' costs. The subsequent sections of this article are structured as follows: Section Methodology and Scope highlights the methodology and scope of the article; cost estimation is discussed in Section Cost Estimation; finally, results and discussion along with conclusions are presented in Section Results and Discussion and Section Conclusion, respectively. All costs indicated in this article are in 2014 Canadian dollars[2] unless otherwise specified.

Methodology and scope

Site selection and energy logistics

The wind energy generation potential is underpinned by the resource quality (mainly governed by the wind speed) and availability in a particular jurisdiction. For a given jurisdiction, the ideal site is such that the location of the wind resource and end-use hydrogen demand are coincident – this will increase the cost competitiveness of the plant. In the Alberta context, as shown in Table 1, as of 2009, the wind generation capacity of the province amounted to 563 MW [47,48]. Alberta's wind energy endowment is located in the southern region of the province, as indicated by the wind farm development in this area (see Fig. 3) [6]. For the plant proposed in this study, 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 electrolyser farm is located for hydrogen production. Pincher Creek serves as the site for the electrolyser farm due to the high density of wind farms in this area relative to other regions in Southern Alberta (see Fig. 3), as well as for comparative reasons with previous studies [6,25]. Furthermore, the nature of the energy logistics pertaining to the plant, facilitates an enhanced capacity factor of the electrolyser farm - due to the geographically dispersed nature of the wind farm network on a localised level. This is considered to be a more efficient and pragmatic alternative to the option of having electrolyser farms situated at each wind farm location, where the capacity factor of the electrolysers are inhibited by the fact that they are constrained to the energy yield of a single wind farm as opposed to a broader localised network of wind farms.

Wind-hydrogen plant description

The FUNNEL – COST – H2 – WIND (FUNdamental eNgineering principlEs-based modeL for COST estimation of hydrogen (H_2) from WIND) plant model proposed in this paper, has a capacity of 563 MW which corresponds to the installed grid connected capacity in Alberta as of 2009 (see Fig. 4). The plant has eight unique operating modes which are described in Table 2. A control unit is employed in the plant to govern its energy management, using a robust algorithm that determines its operational mode for any given hour of the year (see Section Integrated Techno-Economic Model Development for further details). In addition, a rectifier and a buck converter are used for AC/DC conversion, depending on the operational mode of the plant. This is because, due to the energy from the wind farms being of a high voltage, after the rectifier has converted the energy from AC to DC, the buck converter steps down the high voltage DC to a lower voltage suitable for the battery/electrolyser units. A battery is used to smoothen the energy derived from wind, and feed the electrolyser unit with the energy requisite for hydrogen production. Alternatively, the battery is simply used for energy storage when required. Once hydrogen is produced, a compressor is then used to elevate its pressure so as to facilitate pipeline transportation (it is important to point out that the energy for compression is derived from the electrical grid and thus, constitutes a source of operational GHG emissions; the degree to which is governed by the emissions intensity of the grid). In turn, the pipeline transports the hydrogen produced to the bitumen upgrader for consumption.

[2] Where necessary, an inflation rate of 2% has been used to convert all costs into 2014 \$CAD. Furthermore, currency rates of \$1CAD = \$1US; \$1.3CAD = €1; \$1.6CAD = £1 are adopted in this paper.

Table 1 – Grid-connected wind farm generation capacity in Alberta as of 2009 [47,48].

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
Soderglen 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

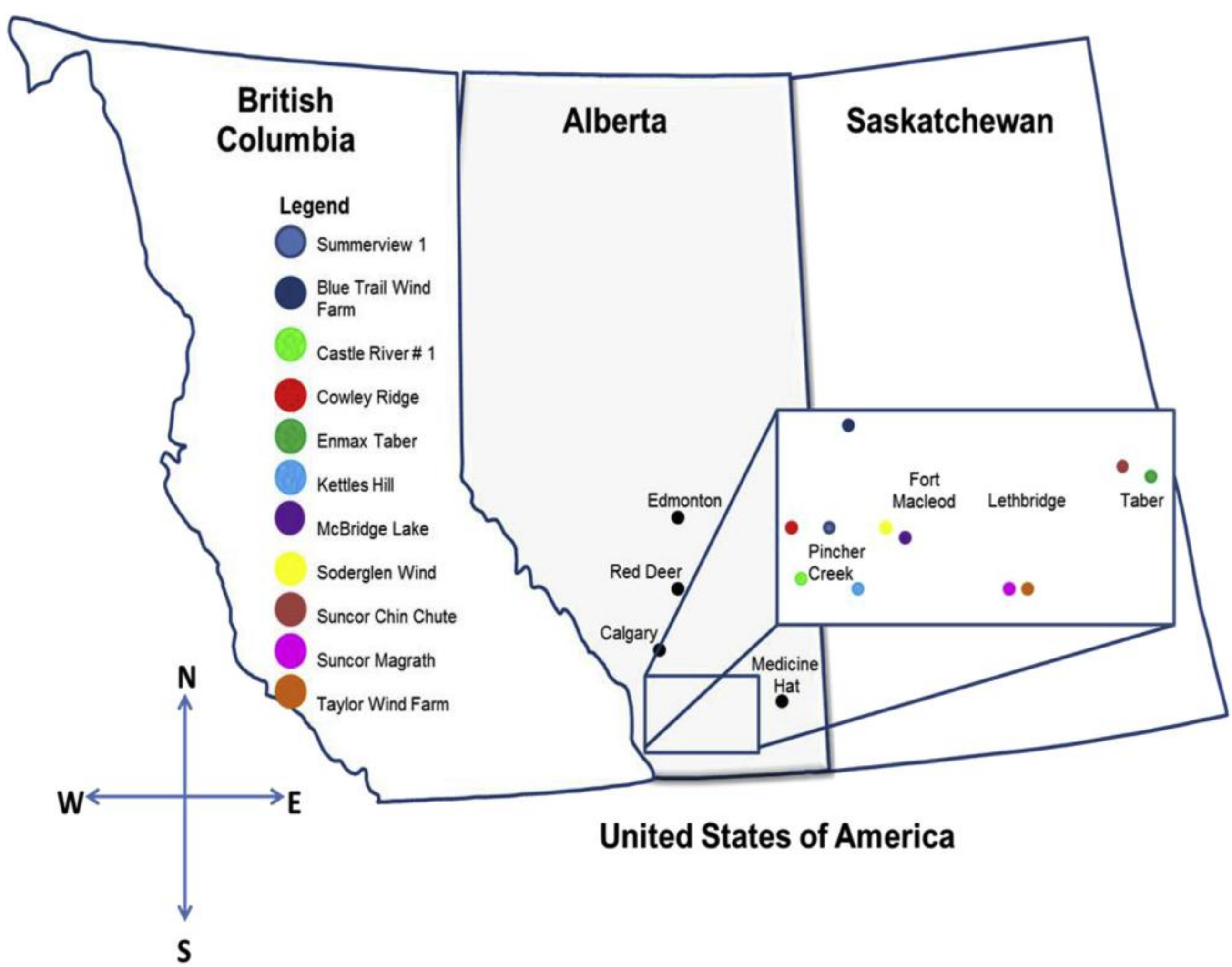

Fig. 3 – Geographical depiction of grid-connected wind farm locations in Alberta (2009) – Reproduced with permission from Olateju, Monds and Kumar (2014) [6]. ©Elsevier B.V.

Battery selection

A summary of the salient characteristics of each battery type is presented below; however, a comprehensive review of batteries along with other energy storage technologies can be found in literature [49–51].

Lead-acid batteries are the most technologically mature and most widely used battery type [33,50,51]. The principal

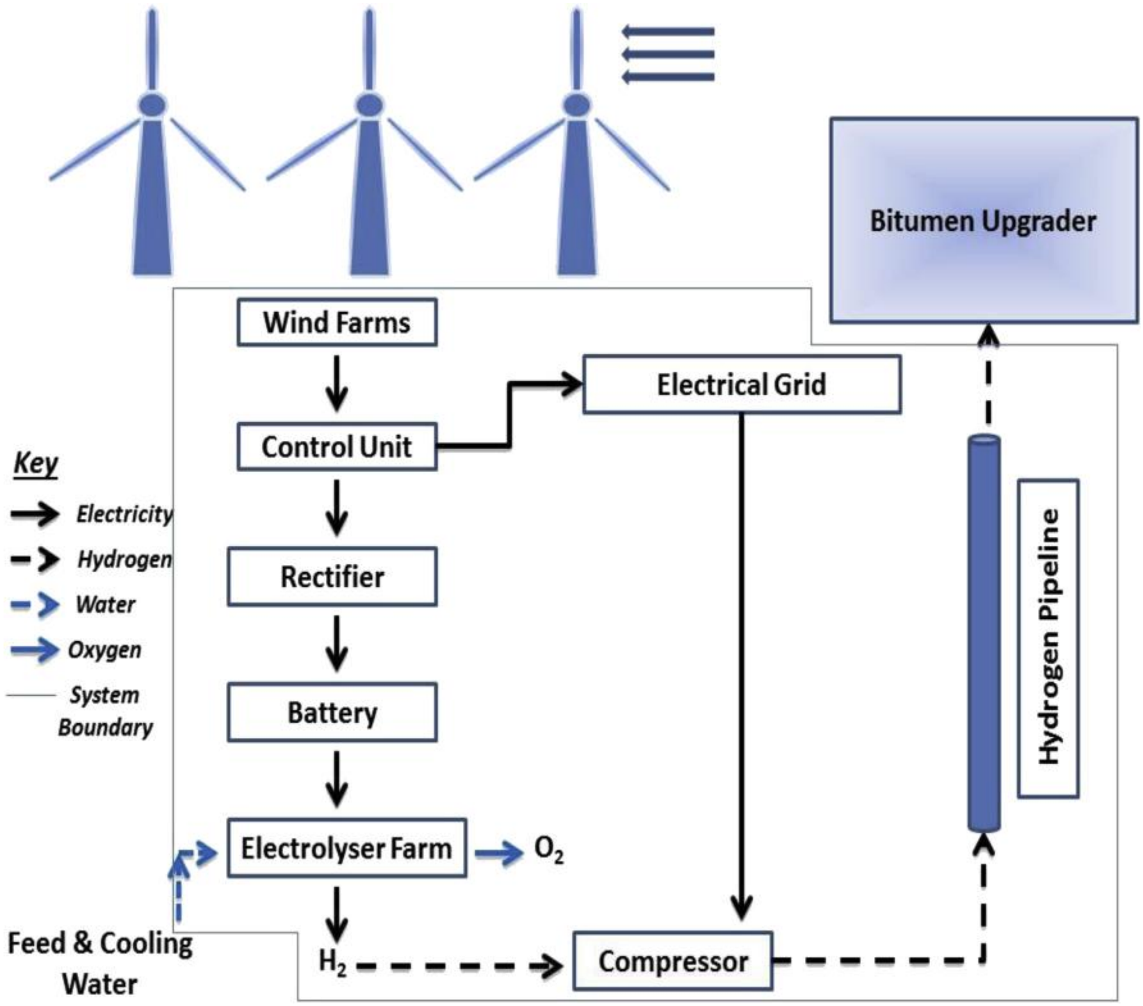

Fig. 4 – Conceptual schematic of the wind-hydrogen plant.

merits associated with these batteries are their inexpensive capital cost ($50–310/kWh), and relatively high roundtrip efficiency (75–80%) [50,51]. However, lead-acid batteries, depending on the depth of charge, have short cycle lives in the range of 200–1800 full equivalent cycles [50,51] – this stems from parasitic reactions such as positive plate corrosion along with the formation of lead sulphate instead of lead oxide (which occurs during normal operation) [52]. This is likely to result in significant replacement/maintenance costs over the wind-hydrogen plant's lifetime. Discharging constraints are associated with this battery type; their state of charge cannot be lower than 40% of their capacity [33]. Consequently, for the application of interest, this battery is prone to underutilization, which inhibits the battery capacity factor, resulting in cost inefficiencies. The battery capacity factor is defined in this study as the ratio of the energy supplied to the battery, and its maximum energy capacity, over an annual period (Supplementary section).

Nickel-cadium batteries are of two types, sealed and unsealed [50,51]. The sealed type is usually for everyday small-scale applications such as remote devices, lamps etc; hence, this type will not be discussed further. The unsealed type is used for large scale applications where weight and volume are important design constraints, a prime example being aviation [50]. Unlike their lead-acid counterparts, nickel-cadium batteries can be fully discharged, negating the need for a minimum state of charge [33]. That said, they incur considerably higher capital cost ($400–2400/kWh) in comparison to lead-acid batteries and also require periodic venting and water addition during charging, as a result of oxygen and hydrogen formation at the electrodes [50]. Furthermore they have a lower round trip efficiency of 60–72% in comparison to lead-acid batteries [50,51]. More importantly, they are considered ineffective for peak shaving and energy management applications, and the toxicity associated with cadium is another concern [50].

Sodium-sulphur batteries are only second to lead-acid batteries with regards to cost effectiveness, with capital costs in the range of ($180–500/kWh) [49–51,53,54]. They have long cycle lives of up to 20,000 cycles depending on the depth of charge, as well as zero self-discharge [33,51]. They have no minimum state of charge and can be fully discharged [55]. Furthermore, they have a relatively high efficiency of 75–92% and are considered particularly adept for large scale utility energy storage applications [50,51,56,57]. Apart from this, they are especially suitable for economical energy management

Table 2 – Wind-hydrogen plant – modes of operation.

Operational mode	Description	Comments
Mode A	Hydrogen production only.	The aggregate[a] amount of energy available to the plant is sufficient for hydrogen production only.
Mode B	Hydrogen production with energy storage.	The excess energy available is stored in the battery due to the unavailability of premium (peak) electricity prices.
Mode C	Hydrogen production with premium electricity sales.	The excess energy available is sold to the grid due to the availability of premium electricity prices.
Mode D	Hydrogen production with non-premium electricity sales.	This occurs when the battery capacity is undersized relative to the surplus energy that needs to be stored. Hydrogen is produced with the use of the grid as a dump-load for any surplus amount of energy. Here, grid sales occur irrespective of the pool price[b].
Mode E	Electricity is sold to the grid only.	This occurs for the following operating conditions: a) When the aggregate amount of energy in the plant does not meet the minimum charging threshold for the battery. b) When the aggregate amount of energy surpasses the minimum threshold for battery charging, however, the energy falls short of the minimum electrolyser energy requirement for H_2 production, and premium electricity prices are available on the grid. c) When the aggregate energy in the plant surpasses the battery capacity and the maximum energy that can be supplied by the battery does not meet the electrolyser minimum energy demand, along with premium prices being available on the grid.
Mode F	Energy storage only.	This occurs when the aggregate energy surpasses the threshold for battery charging, however, the energy falls short of the minimum electrolyser energy requirement for H_2 production, and premium electricity prices are not available on the grid.
Mode G	Energy storage occurs in addition to the use of the grid as a dump load.	This occurs when the aggregate energy in the plant surpasses the battery capacity and the maximum energy that can be supplied by the battery does not meet the electrolyser minimum energy demand. Here, grid sales occur irrespective of the pool price.
Mode H	Plant lull.	

[a] This is refers to the sum of the average energy produced by the wind turbine for a particular hour, and the energy contained in the battery for the same hour.
[b] This is the term used to refer to the hourly wholesale electricity price in Alberta's liberalized electricity market.

applications including: load levelling, power quality, peak shaving as well as renewable energy management and integration [33,49–51]. The principal drawback of sodium-sulphur batteries is their requirement for high temperature operation (300–350 °C for optimal battery performance) and thermal management [33,49–51]. Notwithstanding, some authors are of the contention that once Na-S batteries are running, the heat produced by charging and discharging cycles is sufficient to maintain operating temperatures and typically no external source is required [56,57].

Taking the characteristics of the different battery types into consideration, sodium-sulphur batteries are adopted for the wind-hydrogen plant proposed. This is mainly due to their suitability for large scale energy storage and energy management applications, their inexpensive capital cost and high flexibility of charging/discharging depth. The superior performance of Na-S batteries is evidenced by their widespread application for large scale wind energy installations across the globe [50]. The specification of the sodium sulphur battery unit utilized in this study is provided in Table 3.

Electrolyser selection

The current electrolyser (electrolysis) technologies that dominate the pertinent literature can be sub-divided into three main classes, namely: alkaline electrolysers, proton exchange membrane (PEM) electrolysers, and high temperature electrolysers (HTE) [25]. Relative to other electrolytic options, alkaline electrolysers are adopted in this study as a result of their superior technological maturity, large scale hydrogen flow rates, and relatively inexpensive capital cost [25]. For a more detailed examination of the aforementioned electrolyser pathways, the reader is referred to the work by Olateju & Kumar [25].

Electrolyser modelling

Previous studies have presented 'element-level' electrolyser models, where the authors have characterized the operating voltage of the electrolyser as a function of its operating temperature, current density and characteristic over-potentials (which are also temperature dependent), via a hybrid of electro-chemical and thermodynamic relations [41,59,60]. This modelling paradigm allows for a more robust and dynamic resolution of the electrolyser nominal efficiency, facilitating a more precise simulation of hydrogen yield from a given electrolyser. However, these aforementioned models are predicated upon empirical equations; the coefficients of which have to be ascertained for particular electrolyser via experiments [59,60]. As such, the models cannot be readily generalized; limiting their utility in contexts where a broad number of electrolyser models/capacities and number of units need to be evaluated as part of an integrated energy system. Moreover, some authors have compared these element-level models to those where the nominal efficiency of the electrolyser is assumed to be independent of temperature – the difference in hydrogen yields were in the order of 3% [59].

With this in mind, in this paper, a systems-level approach is implemented in the modelling of the performance of the electrolyser, based on its salient characteristics and the energy input from the battery (which ultimately emanates from the wind turbine). This study assumes that the nominal efficiency of the electrolyser does not change materially during its operation, due to the role of the battery, which delivers a power supply with significantly reduced perturbation - in other words, the electrolyser operates at the constant, nominal current density. In essence, the framework adopted in this paper facilitates modelling flexibility and generalization, without compromising on the accuracy of hydrogen yield (vis-à-vis element level models).

A total of six different electrolyser sizes were considered in this study, the performance specifications of each electrolyser are outlined in Table 4. It is worth pointing out that the minimum electrolyser power requirement for all electrolysers has been determined based on a proportional relationship between the maximum flow rate and maximum power demand (rated power) of the electrolyser as shown in Eq. (1) [6]. The rationale behind this approach is the fact that the minimum operating threshold for electrolysers varies widely in the literature; ranging from 5 to 50% of their rated power [61,62], depending on the scale and manufacturer of the unit. Thus, for reasons of consistency, this methodology has been adopted.

As opposed to the operation of the electrolyser at 73% of its nominal efficiency in previous studies by the authors [6,25], the nominal efficiency of the electrolyser is assumed to be maintained in this study (see Table 4), due to the role of the battery (as explained previously); the sodium sulphur battery

Table 3 – Sodium-sulphur battery specification.

Parameter	Value	Sources/Comments
Manufacturer	NGK Insulators ltd.	[58]
Energy rating (MWh)	6	[58]. A minimum energy threshold of 5% rated capacity was adopted in this study. This was done to limit the adverse effect of deep depths of discharge on the battery's operating life.
Power rating (MW)	1	[58]
DC Efficiency (%)	85	[58]
Operating Temperature (^{0}C)	300–350	[58]. Operating temperature is assumed to be maintained by heat evolution during charging and discharging cycles; no external heat source required [56,57].
Nominal operating life (yrs)	15	[58]. The nominal life corresponds to 300 charge–discharge cycles per year at full rated energy capacity (4500 total cycles). As a conservative estimate, a service life of 10 yrs has been assumed in this study.

Table 4 – Electrolyser size range [63,64].

Electrolyser manufacturer/ model	Min. H_2 flow rate (Nm^3/hr)	Max. H_2 flow rate (Nm^3/hr)	Energy requirement (kWh/Nm^3)	Nominal efficiency (HHV) (%)[d]	Size (kW)	H_2 pressure (bar)	H_2 purity (%)
Norsk Hydro Atmospheric Type No. 5010 (5150 Amp DC) [63]	0[a]	50	4.8[b]	72.4	240	1	99.9 ± 0.1
Norsk Hydro Atmospheric Type No. 5020 (5150 Amp DC) [63]	50	150	4.8[b]	72.4	720	1	99.9 ± 0.1
Norsk Hydro Atmospheric Type No. 5030 (5150 Amp DC) [63]	150	300	4.8[b]	72.4	1440	1	99.9 ± 0.1
Norsk Hydro Atmospheric Type No. 5040 (4000 Amp DC) [63]	300	377	4.8[b]	72.4	1810	1	99.9 ± 0.1
Norsk Hydro Atmospheric Type No. 5040 (5150 Amp DC) [63]	300	485	4.8[b]	72.4	2328	1	99.9 ± 0.1
Industrie Haute Technologie (IHT) Type S-556 [64]	190	760	4.9^{b,c}	70.8	3496	30	99.9 ± 0.1

[a] A minimum flow rate of $1Nm^3/hr$ was utilized in this study.
[b] Indicates the hydrogen production systems level energy requirement specified by the manufacturer [63].
[c] Average value of the energy requirement range (4.6–5.2 kWh/Nm^3) indicated.
[d] The nominal efficiency defined here is the ratio of the ideal energy consumption for water electrolysis (39 kWh/kg H_2) to the nominal energy consumption per unit of hydrogen produced for each electrolyser (at its rated power).

charge/discharge efficiency is assumed to be 85%; the rectifier and compressor efficiency have been taken as 95% and 70% respectively.

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

where: η represents the combined efficiency of the rectifier and battery; EF_{min} and EF_{max} represent the electrolyser maximum and minimum flow rates, respectively. EP_{max} represents the electrolyser rated power.

Integrated techno-economic model development

The FUNNEL – COST – H2 – WIND model utilized in this article was developed using MATLAB [65]. An integral part of the model is an energy management algorithm which considers the hourly average energy generated from wind, the hourly price (grid pool price) of electricity and the salient characteristics of the battery and electrolyser units (see Tables 3 and 4), to determine the operational mode of the plant for each hour in the year. The hourly average energy generated from wind and the hourly grid pool price of electricity, for the year 2009, were provided by the Alberta Electric System Operator AESO [46]. It is important to stress that other components of the plant including the pipeline and compressor, are sized in accordance with the performance of the electrolyser and battery units being evaluated by the model. The model aims to determine the plant configuration (i.e. the electrolyser size, number of electrolyser units and number of batteries) that will yield a minimum hydrogen production cost.

As shown in Fig. 5, the energy management algorithm uses the hourly wind generation data and the economic characteristics of the grid in terms of daily peak and off-peak prices (see Fig. 2), to ascertain three principal variables of interest: the hourly amount of hydrogen production, electricity sales to the grid, and energy storage, for each plant configuration being evaluated. Each case is run for a duration of 8760 h so as to ascertain the corresponding annual values. Once these principal variables have been deduced along with other performance metrics, such as the electrolyser and battery capacity factors, auxiliary plant components are sized accordingly. Additionally, cost data including capital, labour, operating and maintenance costs associated with all plant components are utilized in a discounted cash flow (DCF) model. The DCF model allows for the determination of the hydrogen production cost. This process is repeated for all the plant configurations under consideration; i.e. for all the electrolyser sizes and number of units, as well as the number of battery units, for the determination of the optimal plant set up. The hydrogen production cost ($/kg) is the sole variable used to determine the optimal configuration, and an error margin of $0.01/kg H_2 is incorporated in the algorithm to halt/proceed with iterations after successive values of the production cost have been compared.

Determination of optimal H_2 cost

To appreciate the determination of the optimal H_2 cost in the plant, the relative sizing of the wind farm capacity and the electrolyser farm must be addressed. For a grid connected wind-hydrogen plant such as the one proposed in this paper, the electrolyser capacity (MW) must be undersized relative to the capacity of the wind farm (MW), for a competitive hydrogen production cost to be realized [28,39]. This is because the undersized electrolyser operates at a higher capacity factor relative to that of the wind farm (the capacity factor of the wind farm used in the model is 30%). Thus, in this paper, the optimal electrolyser capacity (MW) for the fixed wind farm capacity of 563 MW, is assumed to exist between 1 and 563 MW. The model developed 'surveys' this solution space using 6 different electrolyser sizes (see Table 4) and number of units. For a particular electrolyser size, the number of units is varied incrementally in the model, using interval sizes, to traverse the lower and upper limits of the 'global'

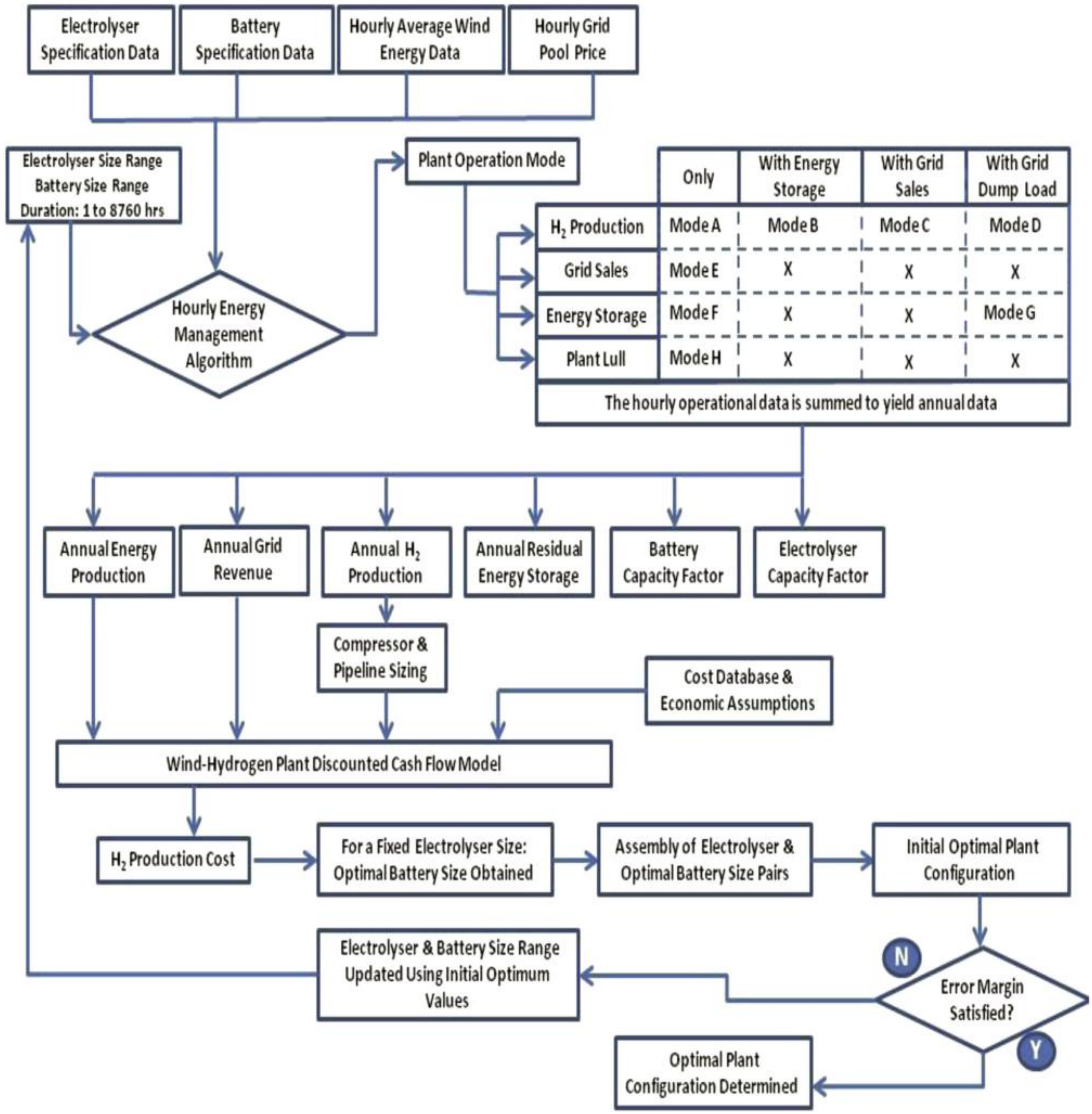

Fig. 5 – Techno-economic modelling framework.

solution space (i.e. an electrolyser farm capacity of 1–563 MW). As illustrated in Fig. 5, using an iterative process, the initial optimal electrolyser size is used to update the limits of the solution space, making it more localized to the region of the initial optimum. The interval size is also updated accordingly. This process continues until the difference between successive hydrogen production costs is less or equal to \$0.01/kg H_2.

To the knowledge of the authors there is no established paradigm for the optimal sizing of a battery (energy storage) relative to an electrolyser unit, in the context of wind-hydrogen systems. In this paper, the optimal sizing of the battery is carried out in tandem with the electrolyser. As in the case of the electrolyser, the number of battery units is varied incrementally using an interval size within a defined range (solution space). The power rating of the battery (each battery unit has a maximum power rating of 1 MW and energy capacity of 6 MWh – see Table 3) was used to define the solution space, and varied from 1 MW to 563 MW to conform to the electrolyser solution space. However, based on the hydrogen production costs yielded, the maximum of this range was adjusted to 100 MW/600 MWh (for the electrolyser farm sizes considered; H_2 costs were observed to escalate significantly beyond a battery capacity 100 MW/600 MWh). As in the case of the electrolyser, the initial optimal battery size is used to ‘localize’ the solution space and update the interval size. This process continues until the difference between successive hydrogen production costs is less or equal to \$0.01/kg H_2. Section Driving Factors for Electrolyser & Battery Sizing elaborates upon the driving factors that govern the size of the battery relative to an electrolyser.

Cost estimation

Electrolyser capital cost

An electrolyser capital cost model developed by Olateju & Kumar [25] (see Fig. 6), which is based on data obtained from pertinent literature and industrial experts, was utilized in the techno-economic model. Furthermore, it is worth pointing out that although the current study involves the capital cost estimation of a significant number of electrolyser units with varying sizes, which will likely facilitate volume discounts along with cost/labour efficiencies, this is not factored into the model. A conservative approach is adopted in this paper, where none of the aforementioned efficiencies are realized. It is worth mentioning that the electrolyser capital cost model is specific to alkaline electrolysers and indicative of the state of the technology as of the early 2000s, not the state of the art. This is as a result of the limited availability of data. Specific capital cost data is considered proprietary by a number of electrolyser manufacturers. Nonetheless, the estimates provided by the model are within reason.

Wind turbine capital cost and auxiliary units costs

The wind turbine capital cost is afforded particular examination in this article, due to the capital intensive nature of wind power and its significant impact on the cost of electricity produced – which fuels electrolytic hydrogen production. The wind turbine itself accounts for about 64–84% of the installed capital costs incurred [66–70]. However, the wind turbine capital cost values provided in literature lack consensus and vary widely across jurisdictions and temporal standpoints; thus introducing a degree of uncertainty in the estimation of wind-hydrogen production costs. For instance, installed capital costs in the United States ranged between \$1400 - \$2900/kW as of 2011; the corresponding range for developed economies is between \$1700 – \$2150/kW; while for China this value is estimated to be \$1300/kW [69,70]. Furthermore, in the period spanning 2001–2004, the average installed capital cost in the United States was \$1300/kW [70]. Thus, it becomes evident that capital cost estimates need to be specific with respect to the market year and jurisdiction they pertain to. With this in mind, an elucidation of the influential factors that govern the turbine's capital cost is duly warranted. In this light, the discussion given here is intended to provide context and insight into the underlying determining factors – thereby providing useful caveats for the capital cost estimate utilized in the model.

From the 1980s to the early 2000s, wind turbine capital costs experienced a dramatic decline; costs fell by more than 65% in the United States, with Denmark experiencing a 55% decrease [68]. However, in the United States, by the mid-2000s, installed capital costs had risen to about \$2000/kW [70]. A number of drivers were behind the evolving nature of wind turbine capital costs over time and space.

Firstly, in the early 2000s, the demand and supply dynamics in the global wind energy market was in a state of excess-supply, with the demand forecasts by the industry being over-exaggerated [66]. However, in the period between 2005 and 2008, demand for wind turbines grew considerably, by over 30% on an annual basis, creating a situation of excess-demand in the market which translated into elevated prices [66]. In concert with the shift from excess-supply to excess-demand, raw material prices, most notably, steel and copper (see Fig. 7), rose significantly over the same period – exerting additional upward pressure on prices [66,67,70]. Other raw material price increases included: lead (367%); aluminum (67%); and acrylonitrile (a raw material for the production of carbon fiber) (48%) [67]. Furthermore, the increased scale, complexity and sophistication of turbine design and their resulting components contributed to price increases [68]. That being said, there was one notable exception to this trend of commodity price volatility leading to considerable increases

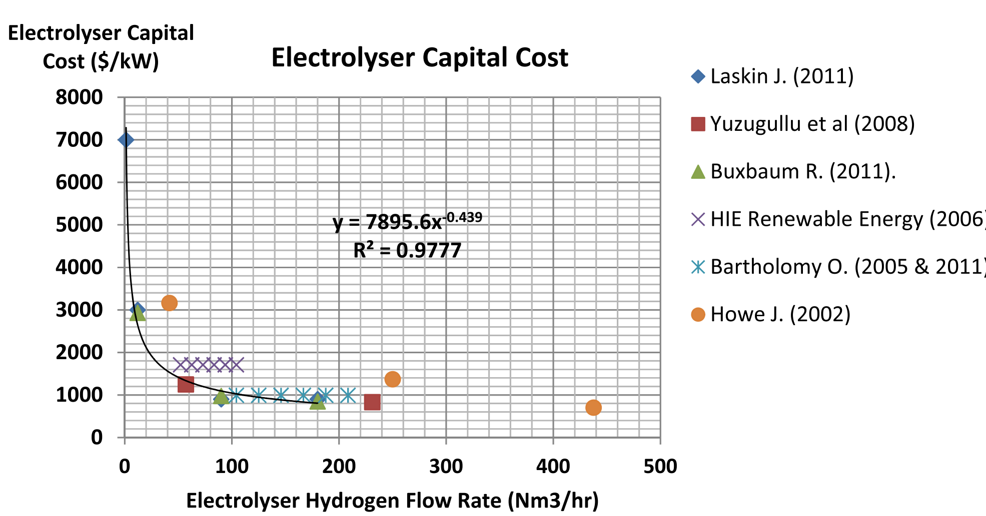

Fig. 6 – Electrolyser capital cost model [25].

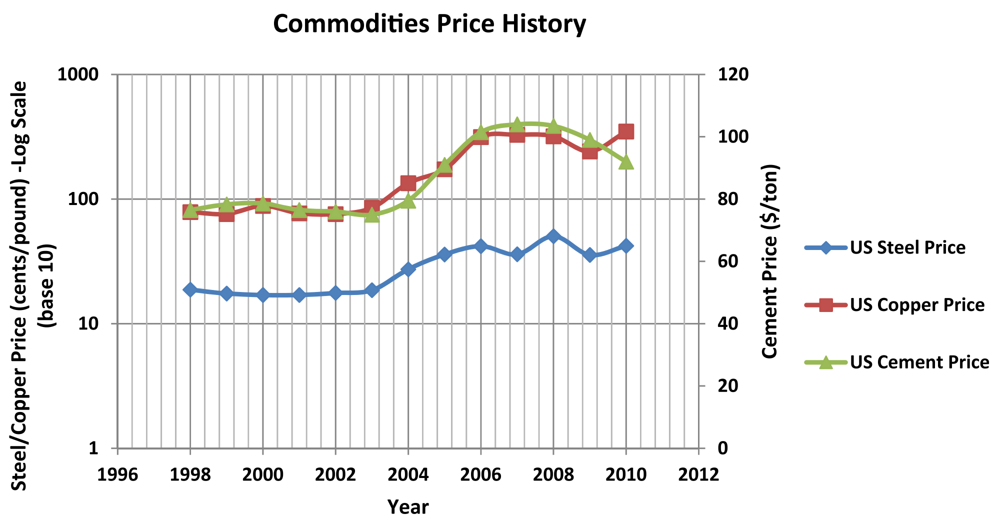

Fig. 7 – Wind turbine commodities price history (United States) – steel, copper and cement [72].

in the installed capital costs for wind energy projects. In the mid-2000s, China remained relatively insulated from these aforementioned market trends with wind turbine capital costs maintaining a level in the range of $1100–$1500/kW; owing to the development of a formidable original equipment manufacturing (OEM) base and the availability of labour at a relatively low cost [68].

In more recent times, it is important to highlight the fact that a reversing trend in wind turbine capital cost has been occurring since 2009–2010 [68,71]. Increased competition between turbine manufacturers, increased manufacturing capacity and lower commodity prices have contributed to this downward trend [71]. In Denmark, capital costs decreased by 22% between 2009 and 2010, with an 8% reduction being observed for Europe as a single entity from 2007 to 2010 [68].

Wind turbine capital cost – economies of scale

In the existing literature, wind-hydrogen models seldom consider the economies of scale that pertain to wind turbines in an explicit fashion. The capital costs utilized are often generic and not specific to a particular wind turbine size [6,15,28,38,39]. The resolution of the economies of scale and its utilization in wind-hydrogen models will translate into improved (realistic) hydrogen cost estimates. A wind turbine (installed) capital cost model was developed for this research, and is illustrated in Fig. 8. Fig. 8 illustrates that smaller wind turbines have a higher specific capital cost ($/kW); the specific capital cost decreases considerably for larger turbine sizes. For a wind-turbine size greater than 1.5 MW, the economies of scale become relatively miniscule and the cost begins to increase gradually for units in the region of 3 MW or higher. It is worth mentioning that units greater than 3 MW are likely to be used offshore; this paper focuses on onshore wind turbines. In order to address some of the specificities of the Albertan economic context, such as higher transportation and labour costs, capital and labour costs are increased by a factor of 1.25. This value is lower in comparison to the magnitude utilized by the authors for a fossil fuel based hydrogen plant [24]. This is to reflect the reduced construction lead time, which can be in the order of months for wind farms as opposed to years for fossil fuel hydrogen plants. Furthermore, the construction of the wind-hydrogen plant is expected to be less labour intensive in comparison to the fossil fuel plant. For comparative purposes, the results yielded by the model were compared to the estimates provided by the United States National Renewable Energy Laboratory (NREL) [73]; the capital cost estimate for a 1.91 MW wind turbine was 19% higher than the NREL estimate which, broadly speaking, is indicative of the elevated capital costs in Canada relative to the United States.

Due to the scale of the wind turbine units being considered in the model and the significant impact they have on capital cost expenditure, volume discounts are also taken into consideration. The volume discount model adopted in this article (see Eq. (2)) is based on the work carried out by Mosetti et al. [74], with adjustments made to suit the magnitude of units being considered. The maximum volume discount achievable in the model amounts to one-third. For the plant size of 563 MW, six different wind turbine sizes were considered, with the developed capital costs for each turbine size given in Table 5. The 2.5 MW turbine had the lowest specific installed capital cost, hence it was utilized as the hypothetical turbine for the plant. It is important to stress that the selection of the 2.5 MW turbine is a real selection in economic terms but hypothetical in energy terms. This is because the real time energy generation data (along with the capacity factor) for the year 2009 is the energy input utilized in the model - this energy is generated from various wind turbine sizes as illustrated in Table 1. The rationale behind the consideration of different turbine sizes is to ascertain a minimum capital cost investment for the wind turbines used in the plant. With regards to the energy generated by the 2.5 MW turbine units, the assumption is that they will yield the same aggregate capacity factor of 30%, as is the case with the real time energy data.

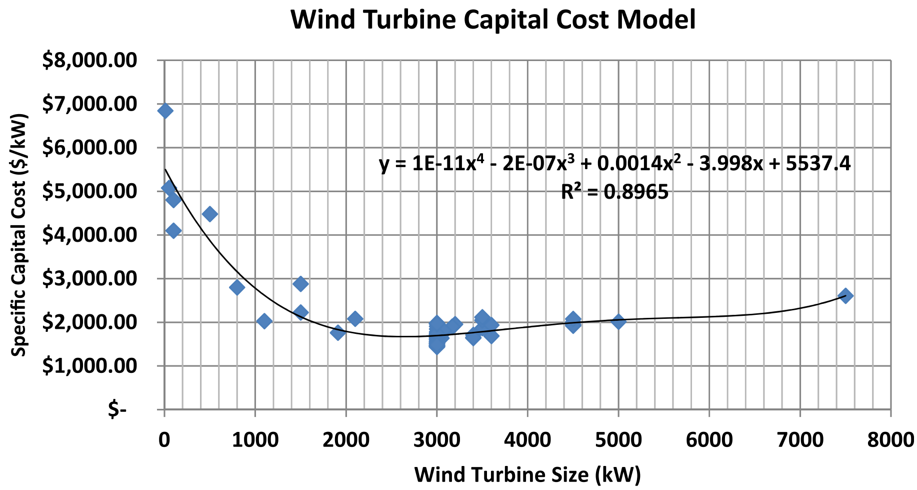

Fig. 8 – Wind turbine capital cost model. Notes: A total of 63 data points were utilized in the model, with data sourced from literature [69,73,79–83].

Table 5 – Wind turbine capital cost.

Wind farm size (MW)	Wind turbine (kW)	Wind turbine capital cost ($/kW)	Number of units	Volume discount	Total installed capital cost ($M)	Total installed capital cost ($/kW)
563	500	3864	1126	0.67	1813	3220
	1000	2749	563	0.68	1317	2339
	1500	2066	376	0.75	1089	1934
	2000	1701	282	0.82	980	1741
	2500	1558	226	0.87	954	1694
	3000	1553	188	0.90	986	1752

$$\text{Volume Discount} = N \times \left(2/3 + 1/3e^{-0.00001 \times N^2}\right) \tag{2}$$

where: N is the number of wind turbine units.

With regards to auxiliary plant costs, Table 6 also provides the O&M costs, as well as costs and service lives pertaining to auxiliary plant equipment and power electronics. Focussing on auxiliary plant costs, it is important to highlight the fact that the cost of purification of the feed water (via reverse osmosis) for the electrolysers, is miniature compared to the cooling water cost [25]. As a result, the latter has been assumed to account for the cost of purification.

Hydrogen pipeline costs

Hydrogen pipeline characterisation

For a hydrogen production flow rate that surpasses 2400 kg/day, pipeline transport of the hydrogen produced is regarded as the most cost efficient means of delivery to market [18,84]. Taking into account the large scale flow rate of the plant, for each plant configuration evaluated in the model, the characterization of the appropriate pipeline dimensions are warranted. The characterization of the hydrogen pipeline required the determination of two principal pipeline parameters, i.e., the pipeline diameter and pipeline length. The diameter of the pipeline was ascertained with the use of the Panhandle – B equation [85]. In this regard, a reverse engineering approach was used to ascertain the diameter requisite for a given hydrogen flow rate. On the other hand, the pipeline distance from the electrolyser farm in Pincher Creek to the bitumen upgrader in the industrial complex in Edmonton, was estimated to be 450 km [25]. This estimate stems from the driving distance between these two locations; however, depending on the logistics of demand, the distance of hydrogen delivery can vary considerably.

Hydrogen pipeline capital cost

A pipeline capital cost model developed by previous authors is adopted in this paper [84]. In addition, the capital cost estimate yielded by this model has been benchmarked against two other similar models provided by Johnson & Ogden [86] as well as Parker [87]. The difference in the resulting estimates ranged from 10 to 18%, which is considered to be a satisfactory range of consensus for the intended purpose. While the model provides a generic cost estimate, the technical, economic and social specificities of a particular hydrogen pipeline project, along with the quality of its construction execution and management, will go a long way in determining the costs realised. Hydrogen pipelines in general have an increased degree of operational risk in comparison to more conventional pipelines (e.g. natural gas), due to the tendency for leakage

Table 6 – Wind turbine auxiliary plant costs.

Cost components	Values	Sources/Comments
Wind farm network connection ($)	12.5% of total wind turbine installed capital cost	[44]
Wind farm electrical infrastructure ($)	9.1% of total wind turbine installed capital cost	[44]
Project development and management cost ($)	12.5% of total wind turbine installed capital cost	[44]
Plant power electronics cost ($/kW) (including rectifier and control unit cost)	35	Estimated relative to the cost specified for a 1 GW wind-hydrogen plant [15].
Electrolyser labour and installation costs ($)	Function of electrolyser size.	10% of electrolyser capital cost.
Electrolyser O&M cost ($/kW/yr)	17	[75]
Electrolyser cell stack replacement cost	Function of electrolyser size.	30% of electrolyser capital cost [28].
Battery Capital Cost ($/kWh)	440	Capital cost is on the higher end of the capital cost range specified in literature ($180–500/kWh) [49–51,53,54].
Battery labour and installation costs ($)	Function of battery size	10% of battery capital cost.
Battery O&M cost ($/kW)	14	[76]
Battery module replacement cost	Function of battery size	30% of battery capital cost
Wind turbine O&M cost (years 1–6) ($/yr)	3% of total installed capital cost	Estimated relative to values utilized in Ref. [6]
Wind turbine O&M cost (years 7–12) ($/yr)	5% of total installed capital cost	Estimated relative to values utilized in Ref. [6]
Wind turbine O&M cost (years 13–20) ($/yr)	8% of total installed capital cost	Estimated relative to values utilized in Ref. [6]
Pincher creek water cost ($/m3)	0.99	[25]
Wind turbine service life (yrs)	20	[28,75]
Electrolyser service life (yrs)	10	[28,77]
Inverter service life (yrs)	10	[78]
Control unit service life (yrs)	10	[25]

and embrittlement of steel. Characterizing the economic implication of these added risks will facilitate more robust capital cost estimates. Fig. 9 provides capital cost estimates for the hydrogen pipeline (in 2010 dollars).

Hydrogen compressor cost

Typically, the desired pressure at which hydrogen should be delivered to the bitumen upgrader is 50 bar [18]. Consequently, in the model developed, hydrogen exits the compressor at 60 bar (inlet pressure of pipeline) so as to be conducive for pipeline transport. For each plant configuration under consideration, a compressor is sized to suit the hydrogen flow rate, using a model provided in an earlier study [88]. In addition, it is important to mention that the hydrogen output pressure from the electrolyser has a significant effect on the cost of the compressor, as this determines the pressure ratio which the compressor will be subjected to. A two stage compressor with an efficiency of 70% and a specific capital cost $970/kW is utilized in the techno-economic model [88].

Principal economic data and model assumptions

In the model developed, a return on equity of 10% along with an inflation rate of 2% was adopted. The wind-hydrogen plant investment is assumed to be serviced by 100% equity; with an operating life of 20 years and a decommissioning cost with a negligible present value [25]. Furthermore, the duration of plant construction is considered to be one year. In addition, oxygen, which is a co-product of the electrolysis process, is also considered as a revenue generation stream. It is important to stress that the price for oxygen varies substantially depending on the market in which it is sold, the scale of production and its level of quality (purity). Price quotes varied from $66.57/Nm^3 for medical grade (99.99% purity) oxygen from retail level vendors [89], to $0.078/Nm^3 for large industrial scale producers [90]. Furthermore, in the published literature a price of $2.77/Nm^3 (originally from Praxair Inc.) is cited by Becalli et al. (2013) [27], however the specific market in which oxygen is sold is not apparent.

The wind-hydrogen plant produces oxygen with a purity level that exceeds 99.99%; hence it is sufficient for medical grade applications in Canada, as evidenced by the specifications provided by Praxair Inc. [91]. In addition, medical grade oxygen trades at a significant premium to industrial application oxygen, which can aid the competitiveness of the plant. The demand for the high purity oxygen at the plant is assumed to come from hospitals, which purchase medical grade oxygen at the plant gate. With this in mind, based on the price quotes aforementioned, medical grade oxygen is assumed to trade at a price that has at least a 30% premium over the ‘generic’ oxygen price $2.77/Nm^3 provided in the existing published literature [27] – i.e. $3.60/Nm^3. Having said that, other costs such as compression, storage, licensing, and handling, are likely to be significant for the sale of medical

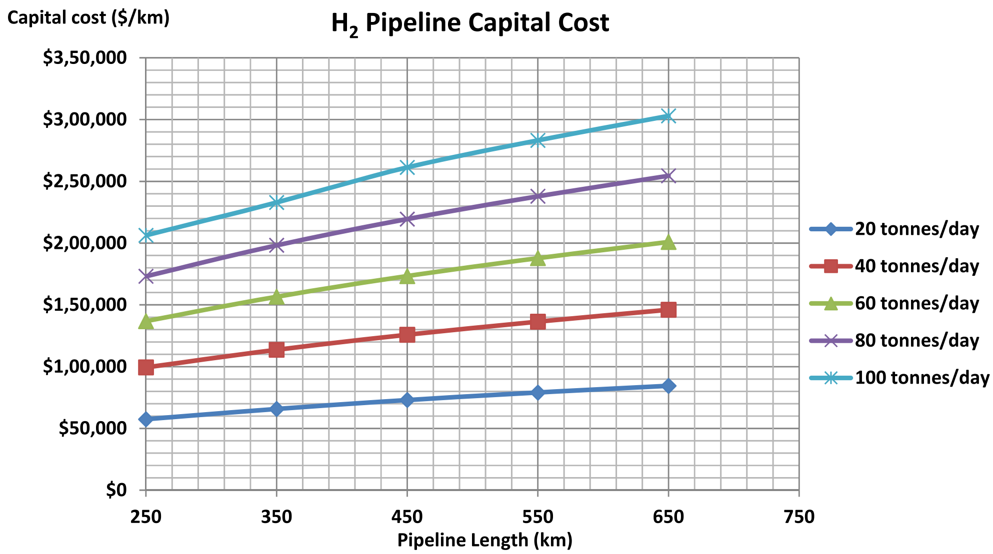

Fig. 9 – Hydrogen pipeline capital cost – Reproduced with permission from Olateju, Monds and Kumar (2014) [6]. © Elsevier B.V. Notes: Cost shown are in 2010 Canadian dollars.

grade oxygen at the plant gate; hence, a profit margin of 20% is assumed i.e. $0.72/Nm^3 or $0.50/kg.

Results and discussion

Hydrogen production cost

Electrolyser farm size

The minimum hydrogen production cost achieved for all the electrolyser farm[3] configurations evaluated, along with their corresponding optimal battery size, is illustrated in Fig. 10. For the six different electrolyser sizes considered, the hydrogen production cost curve exhibits a similar non-linear variation. Initially, significant economies of scale are achieved as the hydrogen production flow rate is increased; however, the economies of scale progressively erode as the magnitude of the flow rate is amplified further. For a given electrolyser, in the vicinity of its maximum hydrogen flow rate, the minimum H_2 production cost is achieved; after this minimum cost, increments to the electrolyser farm size results in production cost increases. At a particular hydrogen flow rate, upon further increases in the number of electrolyser units, a corresponding increase in the hydrogen flow rate does not occur. The hydrogen flow rate remains constant – resulting in a significant rise in the H_2 production cost. These aforementioned trends can be explained as follows:

The economies of scale which are realized initially are attributed to the fact that the wind farm investment cost is fixed for all electrolyser farm configurations. Hence, as the hydrogen production flow rate is augmented with an increase in the electrolyser farm size, the unit cost of hydrogen production decreases accordingly. That being said, a point is reached where the incremental electrolyser doesn't yield additional hydrogen productivity. This is because at this point, the electrolyser farm is oversized relative to the wind farm energy yield. It is also worth highlighting that for a particular hydrogen flow rate to be produced in the plant, each electrolyser size requires significantly different numbers of units. Consequently, the cost to produce a certain hydrogen flow rate varies widely amongst the electrolyser sizes considered. The overall minimum hydrogen production cost of the plant is $9.00/kg H_2, which corresponds to 81 units of the 3496 kW (760 Nm^3/hr) electrolyser and 360 MWh (60 units) of battery capacity. In comparison to SMR, this cost is uncompetitive. Olateju & Kumar [65] provide SMR hydrogen production costs for a number of scenarios in Alberta (with and without carbon capture and sequestration); costs range from $1.87[4]/kg H_2 to $2.60/kg H_2 (2014 dollars).

Battery size

The optimal battery capacity for each electrolyser farm size assessed in the model is also shown in Fig. 10. For a particular range of hydrogen flow rates, the optimal battery capacity for the different electrolyser farm sizes are coincident. With a further increase in the hydrogen flow rate beyond a given range, an increase in the optimal battery size occurs. In general, the optimal battery size increases as the hydrogen flow rate is increased. These observations are quite intuitive. A given battery size is sufficient to produce hydrogen at minimum cost for a specific range of flow rates. Irrespective of the size of the electrolyser or the number of units involved, as long as the hydrogen flow rate falls within range, it can serve as the optimal size. Accordingly, the optimal battery size for the various electrolyser sizes are identical within a particular flow rate range. The general trend of the optimal battery size

[3] An electrolyser farm consists of a fixed electrolyser size and a number of units.

[4] The SMR production costs cited are based on an average natural gas price of $5/GJ over the plant's 25 year lifetime [65].

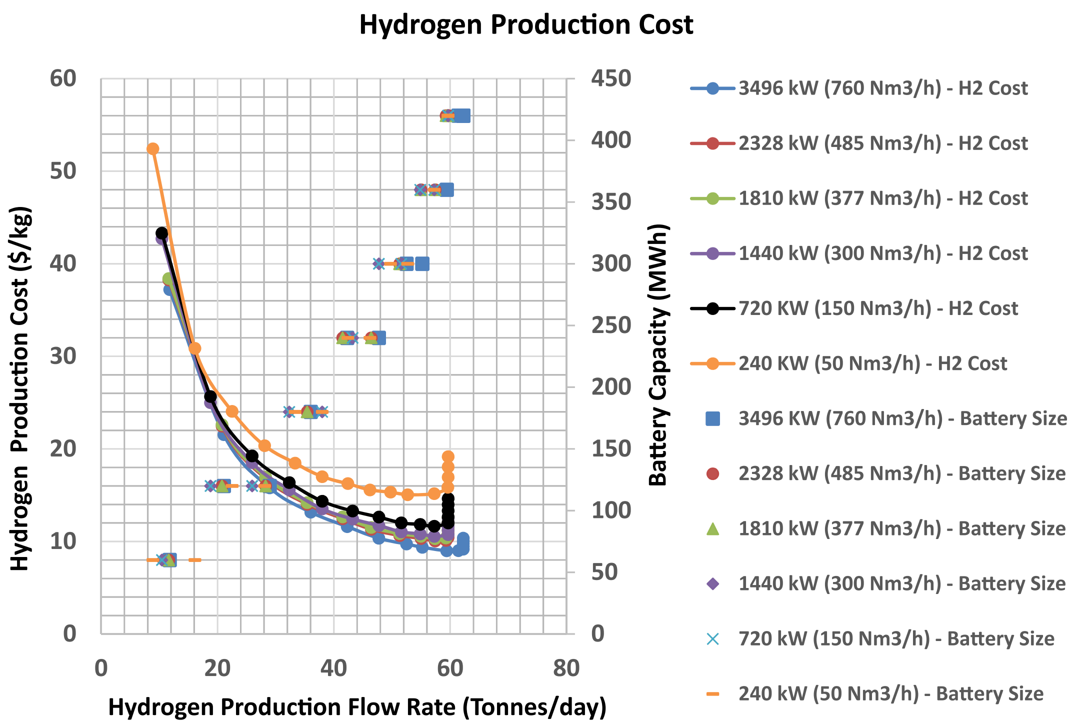

Fig. 10 – Hydrogen production cost.

increasing as the hydrogen flow rate rises is due to the fact that the battery supplies the electrolyser with energy and thus, as increased productivity (H_2 flow rate) is demanded from the electrolyser, the battery has to increase its capacity to deliver energy. Otherwise, the undersized battery will result in a low electrolyser capacity factor and the increased use of the grid as a dump load (i.e. electricity sales to the grid irrespective of the availability of premium electricity prices) – this hinders the cost competitiveness of H_2 production.

Cost distribution

The contribution of the different plant components toward the minimum hydrogen production cost ascertained for each electrolyser size, is provided in Fig. 11. The wind turbine capital cost accounts for the largest portion of the hydrogen production cost for all electrolyser sizes. For the minimum hydrogen production cost determined ($9.00//kg H_2), the wind farm accounts for 63% of this cost. Hence, if existing wind farm assets are used, such that the investment cost of building the wind-hydrogen plant does not include the wind farm costs, the hydrogen production cost is reduced to $3.37/kg H_2. For smaller electrolyser sizes, the electrolyser capital cost accounts for a relatively higher portion of the total cost in comparison to larger electrolysers. This is because smaller electrolysers require a significantly greater number of units and their specific capital costs are also higher. The cost contribution of the battery does not vary significantly for the different electrolyser sizes considered. This is also true for the pipeline and compression costs; however, the cost of compression for the largest electrolyser is relatively minute due to the elevated pressure at which hydrogen is produced (see Table 4). Lastly, the contribution of the power electronics cost is relatively insignificant.

Impact of wind farm size

The installed capacity of wind power in Alberta has changed significantly over the past few years, from a capacity of 563 MW in 2009 to over 1 GW as of 2014. Thus, the effect of the wind farm capacity utilised in the model on the hydrogen cost is worthy of examination. To achieve this, a range of wind farm sizes were considered as shown in Fig. 12. The hourly wind energy generated for the different sizes was assumed to have an identical profile (hourly capacity factor) as the data corresponding to the 563 MW base case. Additionally, the hourly grid pool price was kept constant for all sizes evaluated and a wind turbine size of 2.5 MW was utilized. As shown in Fig. 12, while significant economies of scale are realised for smaller wind farm sizes, for wind farms greater than 900 MW, the economies are relatively small. This finding is analogous to the observation made by previous authors [70,71], where the impact of wind farm scale on the cost of electricity is significant for smaller wind farm sizes, but is insignificant for larger scales.

Hydrogen production cost – sensitivities

The sensitivity of the hydrogen cost estimates, to a number of model parameters, is illustrated in Fig. 13. The effect of the battery and electrolyser efficiency are the most profound on the cost estimates; underscoring the importance of the plant's round-trip efficiency. The wind turbine capital cost has a considerable impact on the hydrogen cost estimates, reaffirming the need to consider the wind turbine capital cost ($/kW) value used in wind-hydrogen models, along with the importance of having a strong OEM base for a given jurisdiction (as this can lower capital costs, e.g., China). Negotiating competitive supply contracts from wind turbine manufacturers is also paramount. The internal rate of return (IRR) has a

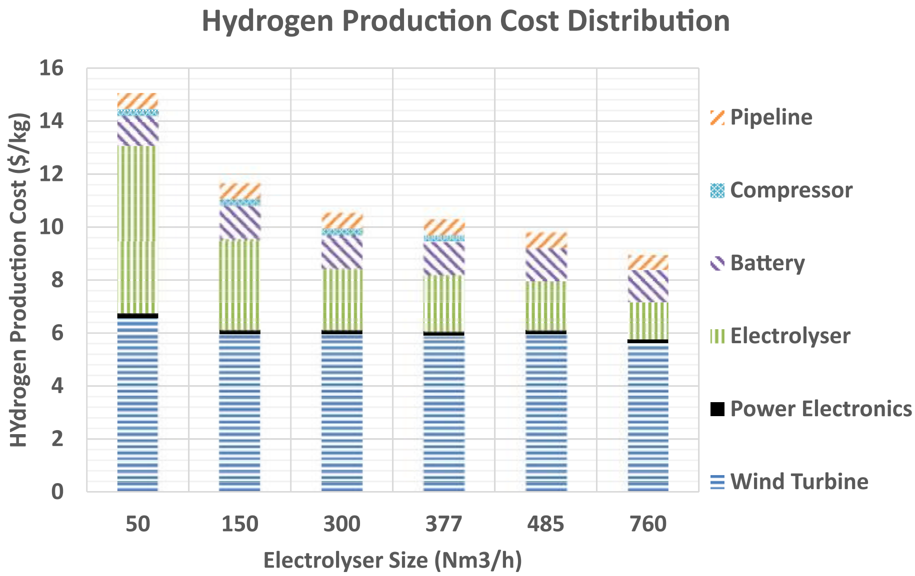

Fig. 11 – Hydrogen production cost distribution.

less significant impact relative to the wind turbine capital cost. The oxygen profit margin has a relatively modest effect on the hydrogen cost estimates.

Driving factors for electrolyser & battery sizing

The optimal battery capacity for a particular electrolyser size, is a strong function of their respective capacity factors as shown in Fig. 14. Note: The graph shown in Fig. 14 corresponds to a fixed electrolyser farm size of 3496 kW (760 Nm^3/hr) x 81 units. The minimum hydrogen production cost is realised when the capacity factor of the electrolyser and battery are approximately equivalent. The underpinnings of this notion stem from the relative sizing of the battery and electrolyser, and the impact it has on their performance. With this in mind, it is important to stress that the energy available to a given electrolyser, which in turn determines its productivity (and by extension, its capacity factor), is constrained by the energy capacity of the battery. Therefore, as shown in Fig. 14, for a fixed electrolyser size, an increase in the battery size translates into an increase in the electrolyser capacity factor; however, this effect dissipates after a particular battery size is attained. This is because, at this juncture, increased storage capacity does not facilitate increased hydrogen production, as the electrolyser is no longer constrained by the battery size, but constrained solely by the energy production of the wind farms. On the other hand, as the battery size is augmented, intuitively, the capacity factor of the battery decreases. Thus, a balance between these two opposing forces facilitates a cost competitive point of operation which translates into a minimum cost. This assertion is further buttressed by the fact that the coincidence of the battery and electrolyser capacity factors leads to a minimum cost for the different electrolyser/battery sizes evaluated in the model.

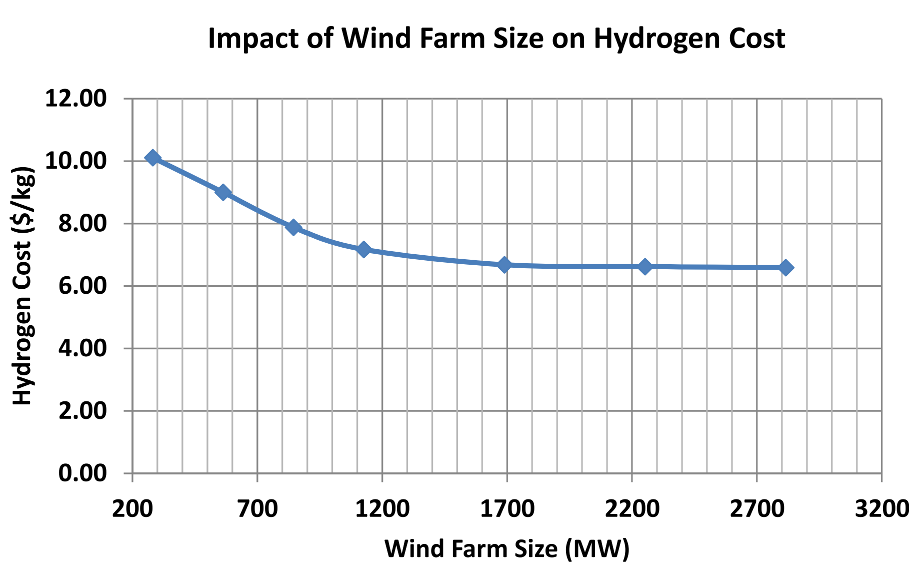

Fig. 12 – Impact of wind farm size on hydrogen production cost.

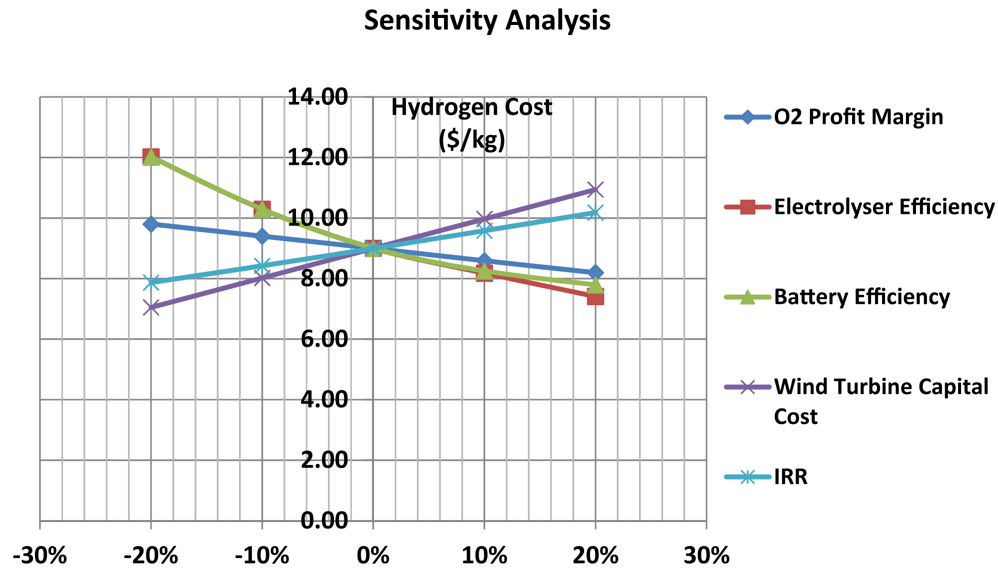

Fig. 13 – Hydrogen production cost sensitivities.

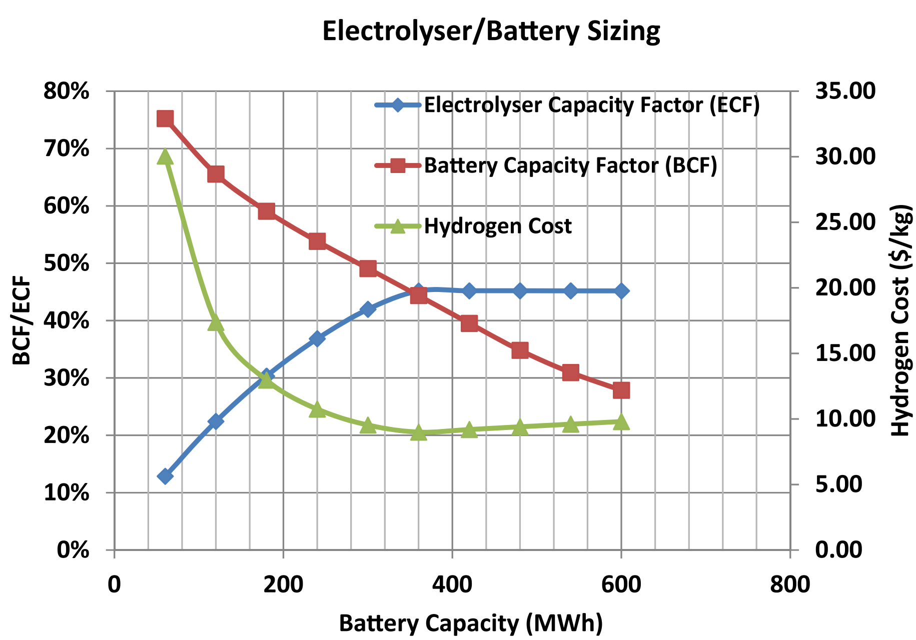

Fig. 14 – Electrolyser and battery sizing.

Techno-economic impact of energy storage in wind-H_2 plants

In comparison to the production cost of an identical plant (without energy storage) outlined in a previous model [6], with updated model inputs consistent with the current model, the added element of energy storage has reduced the minimum hydrogen production cost from \$9.21/kg H_2 to \$9.00/kg H_2. This is a 2.3% decrease, which can be considered negligible. The impediment to increased cost efficiency is driven primarily by the 15% efficiency penalty associated with the battery (85% charge/discharge efficiency), and to a lesser extent by the added capital and operating costs incurred. It is important to stress that energy storage affords the plant two principal benefits: an enhanced electrolyser capacity factor and premium electricity sales. However, this benefit is realised, particularly, for smaller electrolyser farms relative to large ones – owing to the higher propensity for energy storage in the case of small electrolyser farms[5] (see Fig. 15). Despite their enhanced capacity factors and premium electricity sales,

[5] Energy storage is higher for smaller electrolyser farms as the electrolysers have a higher tendency to be undersized with respect to the battery capacity, facilitating an increased amount of excess energy which can be stored in the battery. Intuitively, the degree of energy storage diminishes as the electrolyser farm size is increased, owing to the significant drop in surplus energy available, as a result of the increase in the electrolyser energy demand.

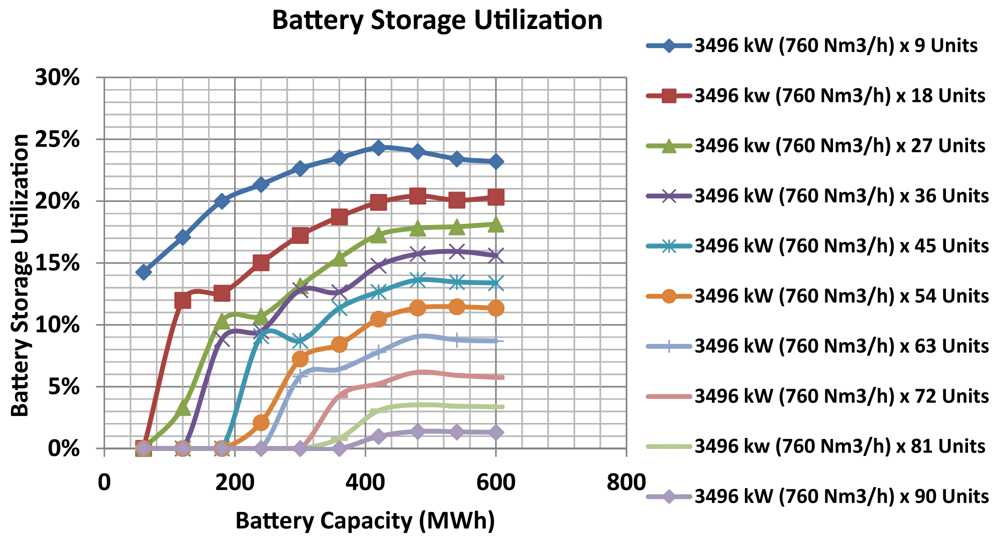

Fig. 15 – Battery storage utilization. Note: Storage utilization is defined here as the percentage of time in a year that energy is retained in the battery for storage purposes (see Equation (1) in the Supplementary section).

smaller electrolysers suffer from reduced hydrogen production flow rates and increased specific capital costs, which do not justify the total capital expenditure of the plant.

Plant operating modes

The operating mode of the plant (see Table 2 for the description of plant operating modes) is governed by the electrolyser size, number of electrolyser units, the number of battery units, the energy generated from the wind farm, and the wholesale electricity (pool) price. As such, the operating modes vary considerably, depending on the electrolyser-battery configuration at hand. Broadly speaking, the plant operating mode will also differ from one jurisdictional context to another; as wind energy profiles and electricity pricing dynamics will vary. To give an illustration of the operating modes realized during the plant's operation, the optimal number and size of electrolysers i.e. 81 units of the 3496 kW (760 Nm^3/hr) electrolyser, is used as an example (see Fig. 16). The impact of the battery capacity on the operating modes is also demonstrated in Fig. 16. Two dominant and opposing trends in Fig. 16 are worth highlighting. On one hand, Mode A (H_2 production only) becomes more prominent as the energy storage capacity of the plant is increased. On the other hand, Mode D (H_2 production only with non-premium electricity sales) becomes less dominant as the energy storage capacity is increased. This is because increasing the battery size reduces the need for non-premium electricity sales that arise due to the inability to store excess energy, as a result of the undersized nature of the battery. The increased battery size allows for the energy that would have been sold to the grid, to be utilized for hydrogen production. The trends exhibited by Mode C and Mode D also emanate from the battery sizing constraints. For smaller battery sizes, these modes are non-existent; however, once the battery size is large enough, the plant is able to make the autonomous decision to store or sell excess electricity at premium prices, alongside hydrogen production. Modes E and F have a negligible occurrence during the plant's operation, and Mode G doesn't occur at all. For about 4% of the year, the plant is at a lull; due to energy not being produced by the wind farms – Mode H. It is important to reiterate that the trends exhibited by the plant, in terms of its operating modes, pertain specifically to the aforementioned electrolyser farm size.

Modelling methodology

The modelling methodology used to ascertain the optimal plant configuration and thus, the minimum hydrogen production cost, was effective, yielding intuitive results and new insights. In this regard, the coincidence of the electrolyser and battery capacity factors, for a minimum hydrogen production cost to be achieved, is an important finding. On another note, the use of variables that can be readily customized to suit various jurisdictional contexts (e.g. peak electricity price hours and the wind energy generation profile) in the model, provides significant flexibility for stakeholders.

A key challenge for the model was establishing the limits of the solution space for the optimal battery size. The approach taken to address this involved the initial assumption that the solution space of the battery is equivalent to that of the electrolyser (i.e. in MW). Based on observed results, the solution space for the battery is then adjusted (see Section Determination of Optimal H_2 Cost), to achieve more efficient computing. From the results yielded, this approach offers a pragmatic solution to the aforementioned challenge, be it less fluid. The main limitation of the methodology developed is that the minimum hydrogen production cost determined, is specific to a particular wind energy capacity and generation profile. That is to say, if the wind energy capacity or generation profile is changed, a different minimum hydrogen production cost would be found.

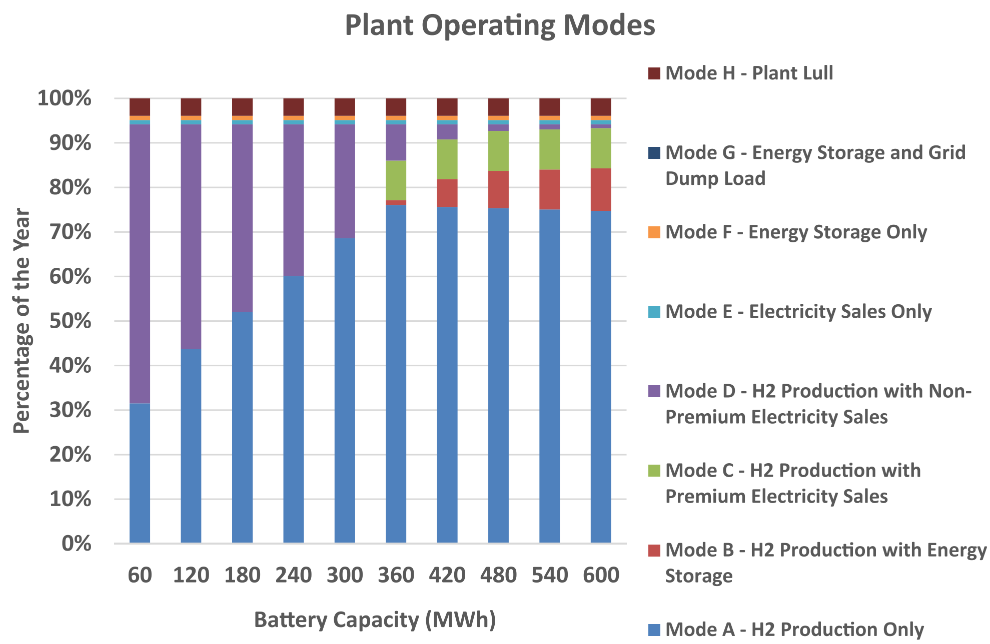

Fig. 16 – Plant operating modes.

Conclusion

This paper involved the development of an integrated wind-hydrogen model termed FUNNEL – COST – H2 – WIND, which utilized real-time wind energy data to ascertain the optimal size of electrolyser, the number of electrolyser units and battery (energy storage) capacities that would yield a minimum hydrogen production cost, whilst functioning in a liberalized electricity market with dynamic prices. The cost to produce a particular hydrogen flow rate varies widely amongst the electrolyser sizes considered. However, for a particular range of hydrogen flow rate, the optimal battery capacity for the different electrolyser sizes are coincident. The overall optimal configuration for the battery and electrolyser in the wind–hydrogen plant, comprised of 81 units of the 3496 kW (760 Nm^3/hr) electrolyser and 360 MWh (60 units) of battery capacity. This translated into a minimum production cost of \$9.00/kg H_2. The wind turbine accounts for a considerable portion of this cost i.e. 63% - hence if existing wind farms are used, the hydrogen production cost amounts to \$3.37/kg H_2.

For a particular electrolyser size, the optimal battery size occurs when the capacity factor of the electrolyser and battery are approximately equivalent. This observation was consistent for all the electrolyser and battery sizes evaluated in the model. Furthermore, the principal benefits of the battery (energy storage) on the wind-hydrogen plant, i.e., enhanced electrolyser capacity factor/premium electricity sales, are realized more readily for smaller electrolyser farms relative to larger ones. Despite the aforementioned benefits of the battery, the decrease in overall plant efficiency and to a lesser extent, increased capital costs, undermine the added benefits of energy storage. For the techno-economic conditions considered in the paper, hydrogen production from wind powered electrolysis is uncompetitive in comparison to SMR. However, depending on the volatility of natural gas prices and the cost of GHG emissions externalities (which is likely to rise in future), wind-hydrogen production can become more competitive.

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Appendix A. Supplementary data

Supplementary data related to this article can be found at http://dx.doi.org/10.1016/j.ijhydene.2016.03.177.

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