A Techno-Economic Assessment of Hydrogen Production from Hydropower in Western Canada for the Upgrading of Bitumen from Oil sands

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Abstract

The demand for hydrogen in conventional and unconventional oil refining industries is considerable. Currently, the predominant source of hydrogen is from fossil fuel production pathways, in particular, steam methane reforming (SMR), which incurs a significant greenhouse gas (GHG) emissions footprint. Thus, alternative environmentally benign sources of hydrogen will be needed in oil refinery complexes the world over, if their greenhouse gas (GHG) emissions footprint is to be reduced materially. In this paper, an integrated data-intensive techno-economic model is developed to provide a credible estimate of hydropower-hydrogen production costs in Western Canada. The minimum hydrogen production cost for the hydropower-hydrogen plant amounts to \$2.43/kg H_2 – this corresponds to an electrolyser farm with 90 units of a 3496 kW (760 Nm^3/h) rated electrolyser. This cost is competitive with SMR/SMR coupled with carbon capture and sequestration (CCS) production costs, which vary from \$1.87/kg H_2 to \$2.60/ kg H_2. This point is buttressed by the fact that if existing hydropower plants are used (hence negating hydropower capital costs), the minimum production cost amounts to \$1.18/ kg H_2.

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Hydrogen from hydro power, under the techno-economic conditions considered here, is competitive compared to SMR.

1 Introduction

Hydrogen is a vital feedstock for the heavy oil industry as it is used to upgrade[2] unconventional heavy crude to synthetic crude oil (SCO) (via hydro-treating and hydro-cracking processes). Relative to heavy crude grades, SCO has an increased market value owing to its reduced viscosity as well as sulphur, nitrogen and metal impurities [1]. In the broader conventional refining complexes world-over, hydrogen is used to enable compliance with fuel standards; most notably, sulphur content [2-4]. Thus, the demand for hydrogen in the refining sector of the oil industry (conventional or unconventional) is formidable and widespread. Alberta has a bitumen upgrading capacity of 1.35 million barrels per day (bpd), with an average of 3.4 kg of H_2 being consumed per barrel of SCO produced [5, 6]. With this in mind, steam methane reforming (SMR) has been the predominant pathway for the production of hydrogen in the bitumen upgrading industry in Alberta, Western Canada. The dominance of SMR in the hydrogen supply mix can be attributed to a multitude of factors; notwithstanding, the most notable of these is the abundance of relatively inexpensive natural gas in North America. While natural gas prices are currently low in Alberta and the broader North American market, they have a history of significant price volatility (see Figure 1). Moreover, the use of natural gas for bitumen upgrading has a significant opportunity cost. The increased penetration of natural gas fired plants in the electricity market, the development of liquefied natural gas (LNG) infrastructure to facilitate exports, along with efforts to facilitate the adoption of natural gas-to-liquids (GTL) automotive fuels in the transportation sector, have the potential to place upward pressure on natural gas prices in North America, particularly in the long term. Aside from this, the greenhouse gas (GHG) emissions footprint of SMR is significant, in the range of 11,000-13,000 tonnes of CO_2 equivalent (CO_{2e}) per tonne of hydrogen produced [7-10]. Considering the fact that recently

[2] As opposed to hydrogen additive upgrading technologies mentioned in this paper, the upgrading of unconventional heavy crude can also be achieved via carbon rejecting technologies such as thermal coking.

announced environmental regulations will introduce an economy-wide carbon tax of $30/tonne CO_{2e} by 2018 [11], this creates an added incentive for the industry to utilize alternative, low-GHG hydrogen production pathways, which are economically competitive.

While costs are highly driven by project specific localized factors, hydropower has the lowest levelised cost of electricity amongst renewable generators in the majority of jurisdictions across the globe [12, 13]. Furthermore, the lifecycle GHG emissions associated with hydropower (1,128 - 2,000 CO_{2e}/tonne H_2), in similar fashion to wind energy, are considered to be one of the lowest amongst renewable pathways [14, 15]. As such, electrolytic hydrogen production powered by hydroelectric energy has the potential to produce hydrogen at a comparative cost to SMR, while mitigating a substantial amount of GHG emissions.

In Alberta, the estimated resource potential for hydropower ranges from 11.8 GW to 15 GW [16, 17] . Furthermore, 75% of this resource potential is situated in the Athabasca, Peace and Slave River basins in the province [17]. Figure 2 and Table 1 show the river basins in Alberta along with the installed capacity of existing hydro power plants as of 2011, respectively. As of 2014, the total installed hydropower capacity in Alberta amounted to 900 MW; accounting for 2.3 % of electricity production in the same year [18]. Research efforts to evaluate the potential of hydro-power based electrolytic hydrogen production in Canada is scarce; one of the possible explanations is the dominance of hydropower as a base load electricity generator in Canada's energy mix. As of 2012, hydropower accounted for 61% of the electricity generated in Canada [5]. Contrastingly, hydropower is used primarily for peak-load applications in the Alberta electricity market, evidenced by its low aggregate capacity factor[3] of 24% as of 2014 [18, 19]. Additionally, for the period of 2005 to 2013, electricity produced from hydropower in Alberta fell by 14.5%[4] [18]; this is in contrast with electricity demand growth which increased by 18.4% from 2005 to 2013 [18]. Hence, the underutilization of Alberta's hydropower capacity can be mitigated by the use of hydropower plants for renewable hydrogen production with a low GHG footprint. In this light, an integrated data-intensive techno-economic model termed FUNNEL – COST – H2 – HYDRO (FUNdamental eNgineering principlEs-based modeL for COST estimation of hydrogen (H_2) from HYDROpower) is developed in this paper, to provide a credible estimate of hydropower-hydrogen production costs in Western Canada.

Against the backdrop of the global climate change agreement achieved at the recent 2015 COP21 United Nations Conference on Climate Change held in Paris, the importance of techno-economic assessments that pertain to renewable sources of hydrogen with a low GHG footprint, is further emphasized. The authors have investigated a number of hydrogen production pathways from different perspectives [9, 20-29], with the exception of hydropower. The existing literature that pertains to the techno-economic modelling of hydropower-hydrogen systems is quite limited in the recent decade when compared to other hydrogen pathways. Notwithstanding, a multitude of systems have been proposed, which are assessed from a techno-economic standpoint with varying degrees of rigor. Each of these systems involves electrolytic hydrogen production using the electrolysis of water. The systems put forward in literature can be broadly categorized into three main themes. First, a number of studies have proposed small scale hydropower-hydrogen

[3] It is important add that hydropower plants are also used for flood control and water management in Alberta. These two operations take precedence over energy production in hydropower plants; as a result, they can lead to low plant capacity factors.
[4] Considering 2014 data, the decrease in hydropower generation is more profound; amounting to a 21.5% drop from 2005 levels [18].

systems, where hydrogen is used to service the electricity/heat generation needs of remote off-grid communities [30-34]. Alternative models are premised upon the use of excess water from hydropower reservoirs, which are 'spilt' without harnessing their potential for hydrogen production [35, 36]. In these studies, the hydrogen produced is used in the electricity generation (peak-load applications/energy storage), transportation (fuel-cell vehicles) or in the value added industries i.e. food, pharmaceuticals and ammonia industries. Furthermore, the dedicated or off-peak use of hydropower plants for hydrogen production has been the basis of other models [37-42], where hydrogen has similar end uses as in the previous category of studies. Other related research to capitalize on hydropower-hydrogen potential, involve its use for methanol production [43]. From the perusal of previous studies a number of noteworthy trends have been identified. With the exception of the model presented by Bellotti et al. 2015 [37], a number of models do not address the optimal sizing (to minimize cost) and configuration of the electrolyser plant. Having said that, Bellotti et al. (2015) [37] does not consider the impact of the hydropower-hydrogen plant functioning in a liberalized electricity market, and the effect of the dynamic electricity prices therein, on sizing considerations. Furthermore, hydrogen yield and electrolyser energy consumption are based upon idealized efficiencies, generic correlations, and assumptions of key metrics (e.g. electrolyser capacity factor) in some cases [30, 31, 35, 38, 39]. Moreover, fixed electricity prices which are not indicative of the dynamics of a liberalized electricity market, are often used to estimate hydrogen production costs [32, 36, 38, 39]. Additionally, some models proposed have limited transparency in terms of the key techno-economic data used, due to confidentiality and other factors [41]. Furthermore, a limited amount of studies present integrated hydropower-hydrogen models which take a holistic account of all unit operations involved from hydrogen production, to its delivery to the end user. The model developed circumvents the limitations highlighted above, translating into the following objectives:

- The development of an integrated grid-connected hydropower-H_2 techno-economic model for the production of renewable hydrogen and estimation of costs, in a liberalized electricity market with dynamic prices.
- The development of a techno-economic framework for the determination of the optimal electrolyser size and number of electrolyser units, which yields a minimum hydrogen production cost, for hydrpower-hydrogen systems.

The latter sections of this paper are structured as follows: Section 2 highlights the methodology and scope of the paper; cost estimation is discussed in Section 3; finally, results and discussion along with the conclusions drawn are presented in sections 4 and 5, respectively. All costs indicated in this paper are in 2014[5] Canadian dollars unless otherwise specified.

[5] 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.

2 Methodology and Scope

2.1 Hydropower-Hydrogen Plant Description

The technical details of a 436 MW hydropower plant proposed by Figueiredo and Flynn (2006) [46] are utilized in the model. The authors use the plant's pumped hydro storage capacity to take advantage of energy arbitrage opportunities on the electricity grid, and thus investigate the optimal sizing of the pump/generator relative to the reservoir (storage) capacity. However, the use of the plant in this current undertaking is for hydrogen production. The plant is located in Grand Cache, south-western Alberta (see Figure 3) – a conceptual schematic of the plant is shown in Figure 4. The hydrogen produced is transported to the Edmonton industrial heartland via a hydrogen pipeline, where a bitumen upgrader consumes the electrolytic hydrogen.

Unlike other intermittent renewables, the need for energy storage to smoothen the erratic profile of the energy generated, so as to allow the electrolyser achieve its rated efficiency and operational life [29], is not needed in the case of hydropower-hydrogen plants due to its non-intermittent energy generation (the hydropower plant in this model operates at constant baseload capacity). This highlights a significant competitive advantage. Apart from the cost savings realized from mitigating the need for energy storage, what is more significant is the higher roundtrip efficiency this affords the plant.

Lastly, as illustrated in Figure 4, the mechanism of hydrogen production is as follows: the hydropower plant (turbine) produces electricity which is converted from AC to DC by the rectifier. The DC energy produced fuels the electrolyser which, while consuming feed water, produces hydrogen. Accordingly, the hydrogen produced is then compressed[6] to the required pressure amenable to pipeline transportation, which is eventually delivered to the bitumen upgrader.

2.2 Energy Management and Quantification of Hydrogen Production

The plant's default operating mode is for hydrogen production only. However, due to its grid connection, instances where the amount of electricity generated by the plant creates an energy surplus relative to electrolyser demand, this is sold to the grid to enhance its economic competitiveness. Additionally, in the event that the electricity produced in the plant falls short of the threshold required for hydrogen production, this is also sold to the grid. The amount of hydrogen produced is a function of the energy output of the plant, the electrolyser energy demand (rated power), number of units, flow rate and efficiency[7]. In essence the plant has three possible operating modes, hydrogen production only; electricity production only; simultaneous production of hydrogen and electricity. The control unit determines the operating mode of the plant based on the energy management flow chart provided in Figure 5. It is also worth mentioning that the oxygen produced as a by-product of the plant (H_2:O_2 production is 2:1) is also sold at the plant gate to augment revenue – further details of the oxygen revenue stream are provided in section 3.4.

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[6] The energy for compression is sourced from the electricity grid at an assumed cost of $70/MWh. This also represents an added GHG emissions footprint for the plant, which is a function of the emissions intensity of the grid.
[7] The difference in the values of efficiencies (energy consumed per unit of hydrogen produced) for the electrolysers evaluated in the model, can be considered negligible (see Table 2 for details). Hence, their relative performance is not dependent on their efficiency, but their size (rated power) in particular.

Depending on the operational mode, the hourly amount of energy generated in the hydropower plant is used to calculate the hourly amount of hydrogen/electricity produced for a period of 8760 hrs, i.e. one year. Furthermore, the hourly wholesale electricity (pool) price is used to calculate the energy revenue for each hour in the year where applicable. Data for the hourly pool[8] price corresponds to the year 2011, and was provided by the Alberta Electric System Operator (AESO) [47]. The summation of the hourly values of hydrogen production/electricity generation, yields the corresponding annual values. These annual values are then used within the FUNNEL – COST – H2 – HYDRO model to calculate the hydrogen production costs (via an embedded discounted cash flow model of the plant) and other performance metrics.

2.3 Electrolyser Selection & Modelling

The existing electrolyser (electrolysis) technologies that are prevalent in the pertinent literature can be broadly categorized into three, namely: alkaline electrolysers, proton exchange membrane (PEM) electrolysers, and high temperature electrolysis (HTE) [28]. Relative to other electrolyser technologies, alkaline electrolysers are utilized in the model presented here due to their superior technological maturity, large scale hydrogen flow rates and relatively inexpensive capital cost. For a more detailed examination of the aforementioned electrolyser pathways, the reader is referred to the work by Olateju & Kumar [28].

In this paper, a systems-level approach is implemented in the modeling of the performance of the electrolyser, based on its salient characteristics. The trade-offs involved with the use of systems-

[8] Pool price refers to the hourly wholesale price of electricity in Alberta's liberalized electricity market.

level models vis-à-vis 'element-level' models, has been addressed comprehensively by the authors [29]. This study assumes that the nominal efficiency of the electrolyser remains constant during its operation, due to the steady generation profile of electricity from the hydropower plant. It is worth pointing out that in previous hydrogen models from intermittent renewable sources developed by the authors, the electrolyser has been assumed to operate at 73% of its nominal efficiency [27, 28].

A total of six different electrolyser sizes were considered in this study, the performance specifications of each electrolyser is outlined in Table 2. Similar to the approach adopted in [27], 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). The rationale behind this approach is the fact that the minimum operating threshold for electrolysers varies widely in literature; ranging from 5-50% [48, 49], depending on the scale and manufacturer of the unit. Thus, for reasons of consistency, this methodology has been adopted. On another note, the efficiency of the rectifier and compressor have been taken as 95% and 70% respectively [50, 51]. Furthermore, it is worth pointing out that the hydropower generator efficiency assumed in this paper is 90%.

$$□□_{□□□} = \frac{(□□_{□□□} \times □□_{□□□})}{(□ \times □□_{□□□})} \qquad \text{(Eq. 1)}$$

Where: □ represents the efficiency of the rectifier; $□□_{□□□}$ and $□□_{□□□}$ represent the electrolyser maximum and minimum flow rates, respectively. $□□_{□□□}$ represents the electrolyser rated power.

3 Cost Estimation

3.1 Hydropower Capital Cost and Auxiliary Units Costs

The hydropower capital cost and auxiliary unit costs for the plant are outlined in Table 3. As mentioned earlier, hydropower capital costs vary significantly and are highly site specific. The capital intensive nature of hydropower plants makes the capital cost value utilized in the model of vital importance. To put the specific installed capital cost adopted in the model in context, it is roughly twice the capital cost incurred for a wind farm of the same capacity [29]. The cost of $4000/kW is also comparable to the value of $3,788/kW specified in a detailed study for the National Renewable Energy Laboratory (NREL) [54]. Tables 3 and 4 put the specific capital cost utilized in this study into broader context.

Still focusing on the capital cost of the hydropower plant, it is worth highlighting the fact that some hydropower plants that are still in operation in Alberta (though underutilized) are likely to have had their capital cost fully recovered (e.g. the Brazeau 355 MW plant, which was built in 1965 [55]). As a result, the use of these types of plants to facilitate hydropower-hydrogen production is particularly promising from an economic perspective, not least because hydropower plants have relatively low operating costs and no fuel cost. However, a holistic economic evaluation that includes capital cost expenditure is undertaken in this paper, to facilitate comparisons with other hydrogen pathways investigated by the authors [26-29].

3.2 Electrolyser Capital Cost

The electrolyser capital cost incorporated into the model is based on the on the work carried out by Olateju & Kumar [28]. The authors aforementioned present a model that yields the specific capital cost of alkaline electrolysers as a function of electrolyser size. This model has been used to account for the capital expenditure for all the different electrolyser farm[9] configurations investigated. It is worth mentioning that volume discounts are likely to be achieved with electrolyser manufacturers in practice, as the purchase of a large number of units is likely to yield strong negotiating power in terms of supply contracts, which will facilitate a more competitive capital cost value. However, a conservative approach is adopted in this paper where none of the aforementioned economies are realized. 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 [29].

3.3 Hydrogen Pipeline and Compressor Cost

Based on the hydrogen flow rate yielded by each electrolyser farm configuration assessed, a hydrogen pipeline is sized using the Panhandle B equation [65]. The pipeline distance estimate of 432 km from Grand Cache to the Edmonton industrial heartland where the bitumen upgrader is located, is based upon the driving distance [66]. The capital cost of the pipeline is accounted

[9] An electrolyser farm consists of a specific electrolyser size and a number of electrolyser units.

for using a model developed in a previous study [67]. The model utilized compares favorably with the estimates of alternative hydrogen pipeline models [68, 69]; with discrepancies falling within a range of 10-18%. Common to all pipelines, the capital cost will be determined by site-specific factors along with the properties of the transport fluid. In the case of hydrogen pipelines, measures to address the potential embrittlement of steel and hydrogen leakage will be particularly important. In general, there is an elevated risk of pipeline operation associated with hydrogen pipelines, relative to other industrial fluids (e.g. CO_2, natural gas etc.), which has to be factored into the cost estimates for improved accuracy [29]. On another note, a compressor is used to elevate the hydrogen pressure to 60 bar so as to facilitate pipeline transport [26, 27]. Similar to the pipeline, a compressor is sized for each electrolyser farm configuration assessed. Further details of the pipeline and compressor specification, as well as their corresponding cost estimates utilized in this paper, can be found in [26].

3.4 Principal Economic Data and Model Assumptions

In the FUNNEL – COST – H2 – HYDRO model, a return on equity of 10% along with an inflation rate of 2% was adopted. The hydropower-hydrogen plant investment is assumed to be serviced by 100% equity; with an operating life of 40 years and a decommissioning cost with a negligible present value. Another assumption is that the plant does not benefit from any renewable energy incentives such as feed-in-tariffs (FIT). Furthermore, the duration of plant construction is considered to be three years. As mentioned earlier, oxygen, which is a by-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 [70], to \$0.078/Nm^3 for large industrial scale producers [71] . Furthermore, in the published literature a price of \$2.77/Nm^3 (originally from Praxair Inc.) is cited by Becalli et al. (2013) [72], however the specific market in which oxygen is sold is not apparent.

The hydropower-hydrogen plant produces oxygen with a purity level that exceeds 99.99%; thus it is compatible with the standards for medical grade applications in Canada, as evidenced by the specifications provided by Praxair Inc. [73]. Furthermore, 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 driven by oxygen consumption in Alberta hospitals and other institutions such as care homes, which purchase medical grade oxygen at the plant gate. In the model, an incremental oxygen revenue of \$0.50/kg O_2 is assumed, based on a selling price of \$3.60/Nm^3 [29].

4 Results & Discussion

4.1 Hydrogen Production Cost

The hydrogen production cost curves for the different electrolyser sizes evaluated, all exhibit a non-linear trend as shown in Figure 6. Significant economies of scale are realised as the hydrogen production flow rate of the plant is increased (it is important to mention that increases in the plant's hydrogen flow rate coincide with increases in the number of electrolyser units). As the flow rate is increased to larger magnitudes, the economies of scale realised decrease progressively, until a minimum hydrogen production cost is achieved. After the minimum cost is achieved, with further increases to the number of electrolyser units, the hydrogen flow rate remains constant; resulting in a rapid rise in the production cost (see Figure 6). This occurs because the electrolyser farm is oversized relative to the amount of energy produced by the hydropower plant.

Figure 6 also shows that for a particular hydrogen flow rate to be produced by the plant, the cost incurred varies significantly depending on the electrolyser size that is used. This is because in order to achieve a given flow rate magnitude, the number of electrolyser units required varies considerably, depending on the electrolyser size. Smaller electrolyser sizes require a significantly higher number of units in comparison to larger electrolysers. It is also worth mentioning that apart from providing more competitive production costs (as seen in Figure 6), the larger sized electrolysers in general allow for energy management, monitoring, operational and maintenance endeavours that are more pragmatic compared to smaller electrolysers, due to the significantly reduced number of units required.

The minimum hydrogen production cost for the hydropower-hydrogen plant amounts to \$2.43/kg H_2 – this corresponds to an electrolyser farm with 90 units of the 3496 kW (760 Nm^3/h) rated electrolyser. This cost is competitive with SMR/SMR-CCS production costs, which vary from \$1.87/kg H_2 to \$2.60/ kg H_2. This point is buttressed by the fact that if existing hydropower plants are used (hence negating hydropower capital costs), the minimum production cost amounts to \$1.18/ kg H_2 (see Figure 7).

4.2 Cost Distribution

For each electrolyser size considered in the model, the minimum H_2 cost distribution is shown in Figure 7. For smaller electrolysers, the cost of the electrolysers units is the most significant cost component; accounting for 60% and 44% of the total hydrogen production cost in the case of the 50 Nm^3/h and 150 Nm^3/h electrolysers, respectively. This is due to the significant number of units required – 1400 and 500 for the 50 Nm^3/h and 150 Nm^3/h electrolysers, respectively; which is an order of magnitude greater than the 90 units required by the largest electrolyser. Apart from the sheer volume of units, the specific capital costs for smaller electrolysers are higher vis-à-vis their larger counterparts; hence, the total electrolyser investment cost is more significant – this also elevates the replacement cost of the electrolysers, which are replaced 3 times during the plant's 40 year lifetime. Moreover, as a result of the relatively high capacity factor of the hydropower plant (which results in a high electrolyser capacity factor despite the high number of units), the costs of running the electrolysers, including: water resource costs, operating and maintenance costs, are high in comparison to larger electrolysers.

The overarching trend indicated in Figure 7 is such that as the electrolyser size increases, the hydropower cost becomes increasing dominant, while the electrolyser cost decreases in significance. The pipeline and compressor cost are relatively consistent amongst the different electrolyser sizes, due to the fact that a similar magnitude of hydrogen flow rate (ranging from 146 – 149 tonnes H_2/day) is transported and compressed for the different minimum cost values of the electrolysers. The compressor cost for the largest electrolyser is relatively minute due to its high hydrogen production pressure (see Table 2). The power electronics cost is relatively insignificant for all electrolyser sizes.

4.3 Hydrogen Production Cost – Sensitivities

The sensitivity[10] of the production cost estimate to key techno-economic parameters is shown in Figure 8. The electrolyser efficiency has the most significant effect on the cost estimates not least because of its dual impact; it influences the amount of hydrogen produced and the amount of surplus energy available to be sold to the grid. Intuitively, the installed capital cost estimate of the hydropower plant also has a formidable effect on the hydrogen production cost. As eluded to earlier, the sensitivity of the installed capital cost is indicative of the highly cost competitive production cost that can be achieved with existing hydropower plants in Alberta (with sunk capital costs) used for hydrogen production. Alternatively, upgrades to existing plants e.g. new generators etc, would also be reflective of a reduction in capital cost expenditure. Lastly, the IRR has a relatively moderate effect on the production cost, while the oxygen profit margin has the least impact of all the parameters considered.

4.4 Electricity Revenue

The amount of electricity revenue made from sales of energy to the grid, as a function of the electrolyser farm size, is illustrated in Figure 9. For the smaller electrolysers, electricity revenue is significant for a wide range of electrolyser farm sizes. This is because the surplus amount of energy available from the hydropower plant is sufficiently high enough to command meaningful revenue from the grid. In the case of larger electrolysers, electricity revenue is significant for a narrow range of electrolyser farm sizes. Intuitively, this is due to a reduced amount of surplus energy being available for sale in this context. Additionally, as a result of their increased power

[10]The sensitivity analysis carried out is based upon the plant configuration which yielded the minimum hydrogen production cost – 90 units of the 3496 kW (760 Nm^3/h) electrolyser.

capacity (kW), a much smaller number of units will provide the same level of energy demand as in the case of a larger number of units for the smaller electrolysers.

The electricity revenue is also a function of the wholesale electricity (pool) price. Hence, if the value of energy in the electricity market appreciates, smaller electrolysers in particular will become more cost competitive, with the opposite being true. It is noteworthy to highlight the fact that the average annual pool price is currently experiencing a downward trend (see Figure 10), partly due to the growth of supply capacity exceeding demand growth in Alberta's electricity market. Thus, generally speaking, the sale of electricity as a by-product from the hydropower-hydrogen plant would not be as profitable as the current case evaluated here suggests[11], based on recent (2014) prices (see Figure 10). On another note, the model developed here assumes that electricity supply bids from the plant, offered into Alberta's deregulated market (merit order system), have a 100% success rate. In reality, the success of a supply bid made by the plant will be dependent on the bids of other generators in the electricity supply mix, along with demand and supply forces. That said, the modelling of the merit order dynamics in a deregulated electricity market is beyond the current scope of work. The use of real time deregulated electricity market prices along with the 100% success rate of supply bids, is appropriate for the intended purpose of this paper. Moreover, in practice, measures such as power purchase agreements (PPA) and forward pricing mechanisms could be established with wholesale consumers of electricity, to limit exposure to the volatility and competitiveness of the deregulated electricity market.

[11] As stated earlier, wholesale electricity price data from 2011 was used in the model. Electricity in this period was valued relatively highly in Alberta's deregulated electricity market, with an annual average price of about \$76/MWh.

4.5 Electrolyser Capacity Factor

The electrolyser capacity factor variation with electrolyser farm size draws some parallels with the case of electricity sales (see Figure 11). Smaller electrolysers are able to maintain ideal (100%) capacity factors over an extended range of electrolyser farm sizes, while this range is much narrower for larger electrolysers. As the electrolyser farm size is increased, the capacity factor initially maintains an ideal value (because of the non-intermittent nature of hydropower generation). However, once the electrolyser farm size attains a magnitude such that the electrolyser demand for maximum hydrogen production supersedes the electricity supply, the capacity factor drops sharply with further increases in the electrolyser farm size. This trend is consistent for all the electrolyser sizes assessed in the model.

5 Conclusion

An integrated data-intensive techno-economic model termed FUNNEL – COST – H2 – HYDRO has been developed in this paper to estimate hydrogen production costs from a hydropower plant which operates in a liberalized electricity market. A number of electrolyser configurations (electrolyser farms) were assessed to determine the minimum cost of hydrogen production. The minimum hydrogen production cost for the hydropower-hydrogen plant amounts to \$2.43/kg H_2 – this corresponds to an electrolyser farm with 90 units of the 3496 kW (760 Nm^3/h) rated electrolyser. This cost is competitive with SMR/SMR-CCS production costs, which vary from \$1.87/kg H_2 to \$2.60/ kg H_2. This point is buttressed by the fact that if existing hydropower plants are used (hence negating hydropower capital costs), the minimum production cost amounts to \$1.18/ kg H_2.

In general, the smaller electrolysers exhibited significant electricity revenue and ideal capacity factors for a broad range of electrolyser farm sizes. However, the higher number of units and specific capital costs which these smaller sizes incur, impeded the achievement of cost efficient production costs. It is worth adding that the energy management, monitoring, operation and maintenance of relatively high numbers of electrolyser units, which pertain to smaller electrolysers, would be prohibitive in many cases. In contrast, even though their capacity factors and electricity revenue were not as extensive, larger electrolysers benefited from lower specific capital costs and a lower number of units – hence, translating into more competitive production costs.

The impact of the electrolyser efficiency and hydropower capital cost estimate on the hydrogen production cost is highly significant. Hydrogen from hydro power, under the techno-economic conditions considered here, is competitive in comparison to SMR. With the consideration of the cost of GHG emissions, the competiveness of hydropower-hydrogen against SMR will be further enhanced.

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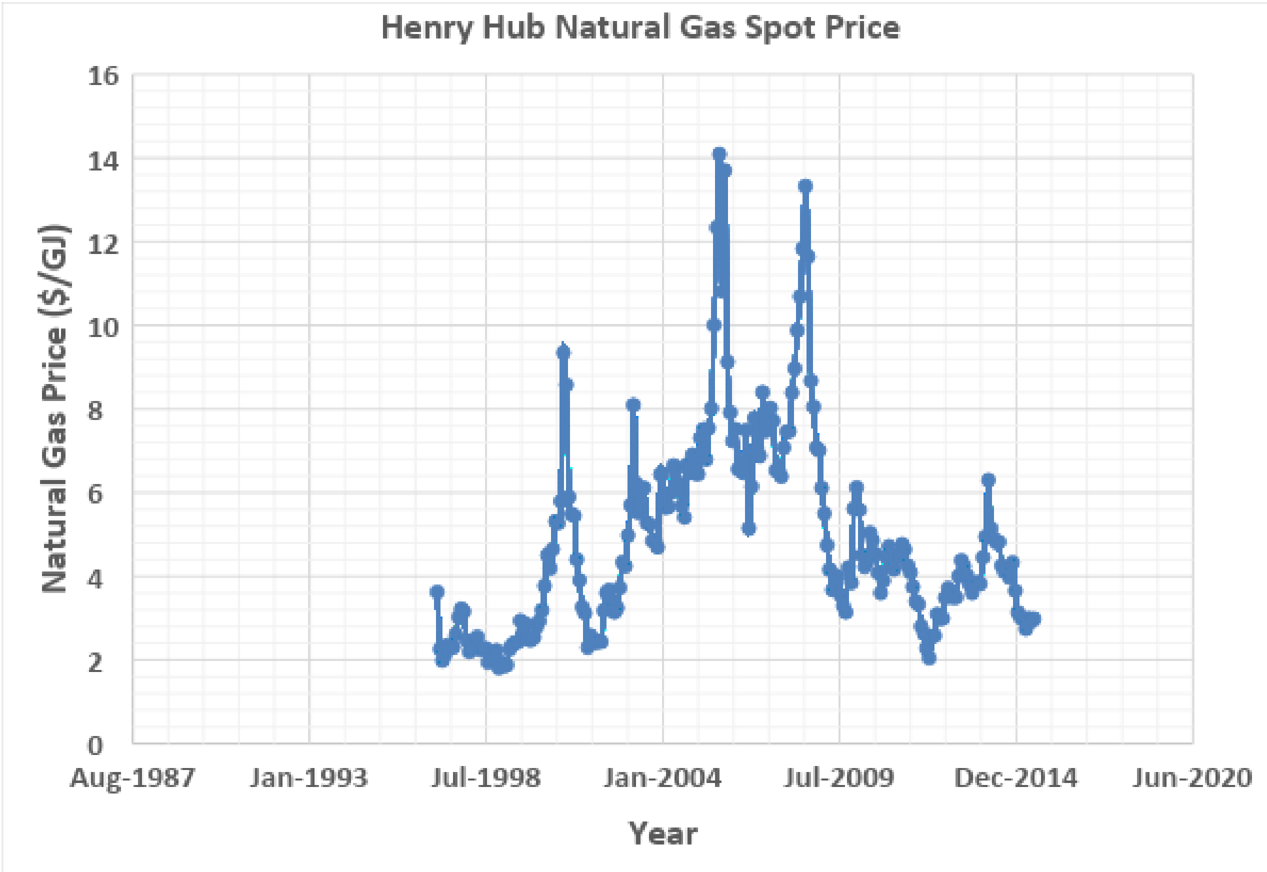


Figure 1: Historical natural gas price in Alberta [44]

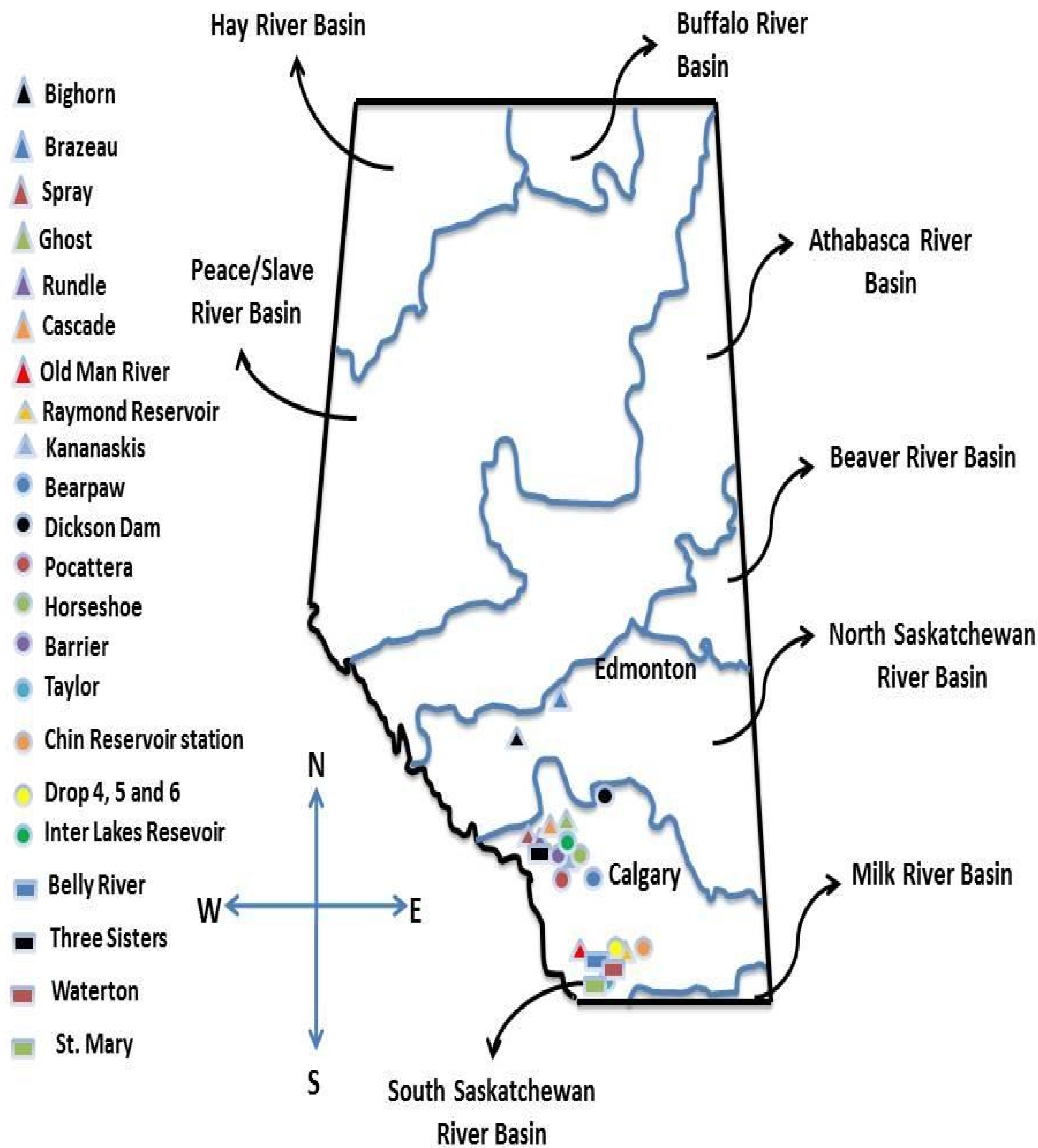


Figure 2: Alberta's river basins and existing hydropower plants (2011)

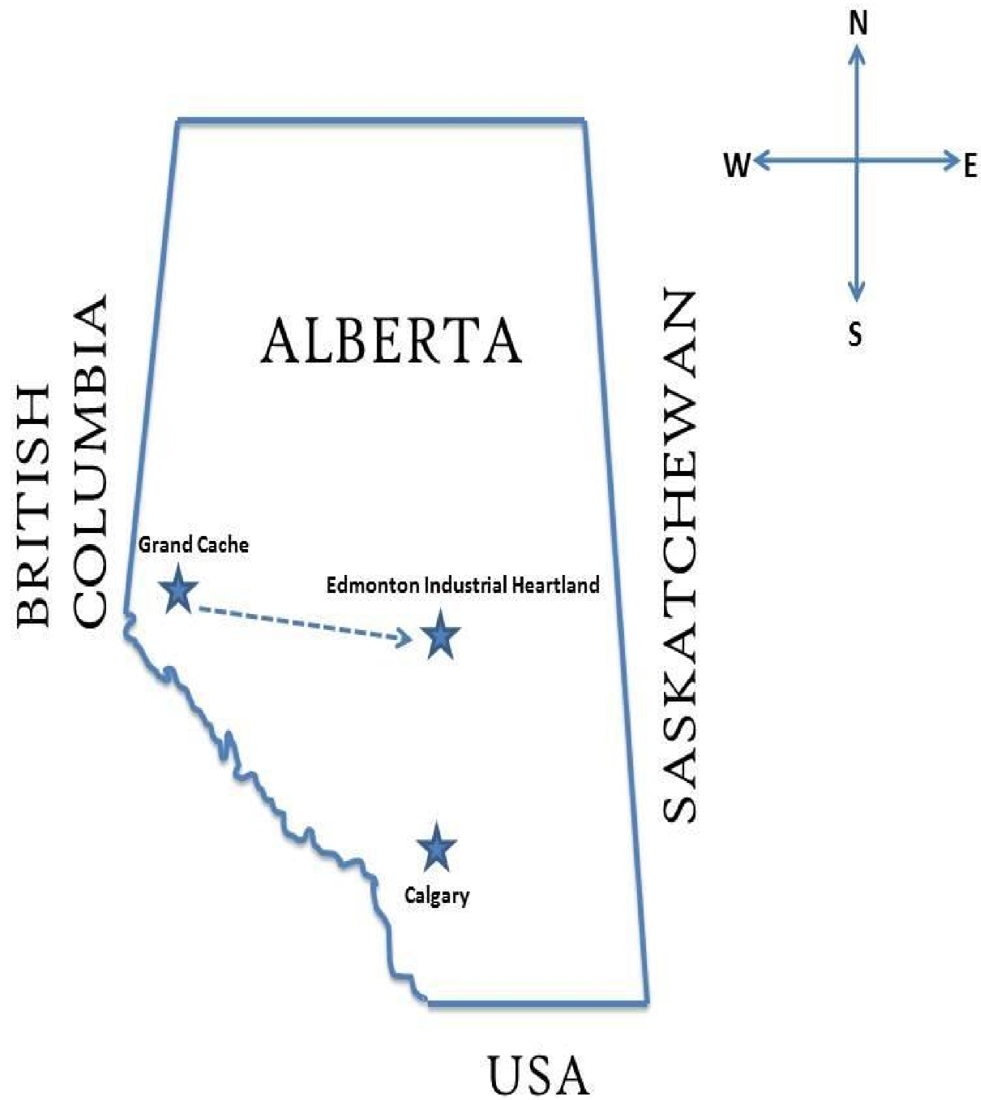


Figure 3: Proposed plant location (Grand Cache) relative to Edmonton Industrial Heartland (Bitumen Upgrader Location).

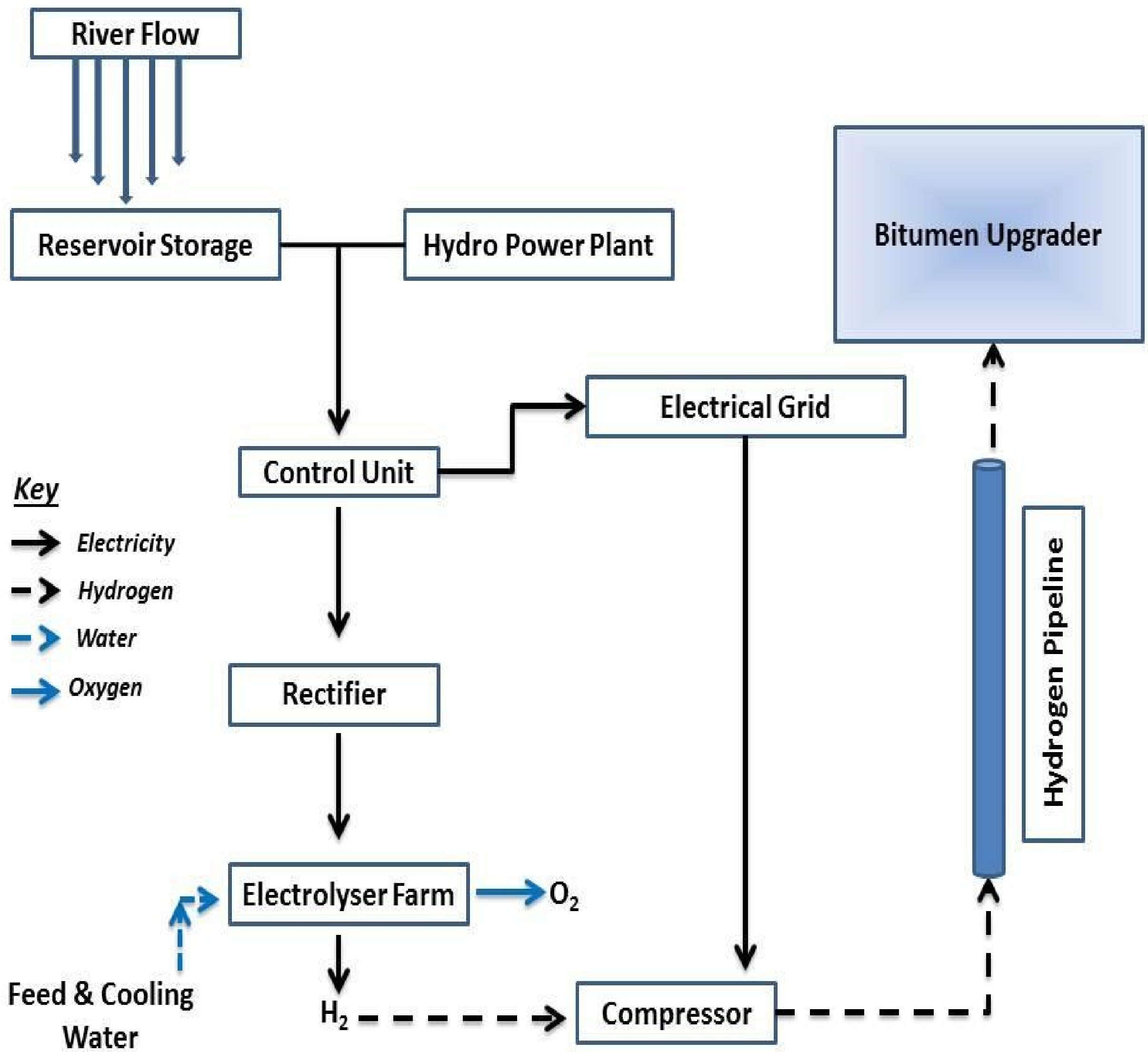
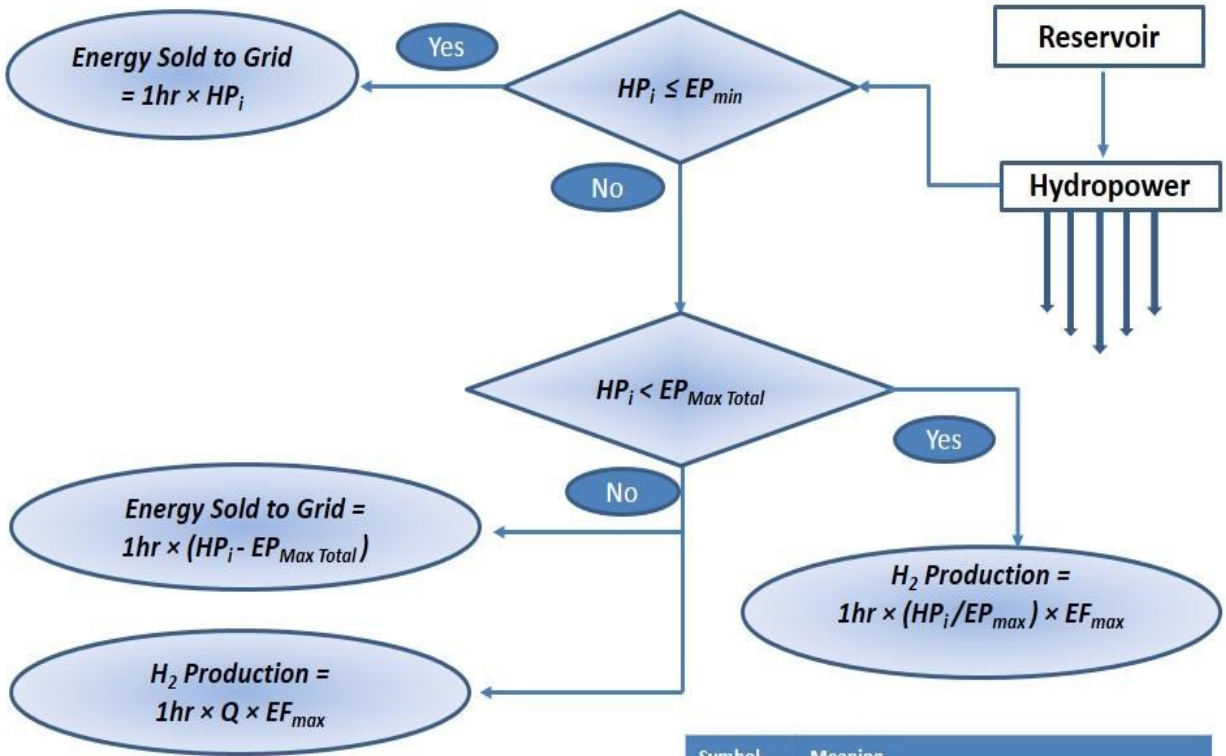


Figure 4: Conceptual schematic of the hydropower-hydrogen plant



Symbol	Meaning
EP_{min}	*Mininmum Electrolyser Power – Single Unit*
EP_{max}	*Maximum Electrolyser Power – Single Unit*
$EP_{Max\ Total}$	*Total Electrolyser Power - Multiple Units*
EF_{max}	*Maximum Electrolyser Flow Rate – Single Unit*
HP_i	*Hydropower Hourly Generation*
Q	*Number of Electrolyser Units*

Figure 5: Energy management flow chart.

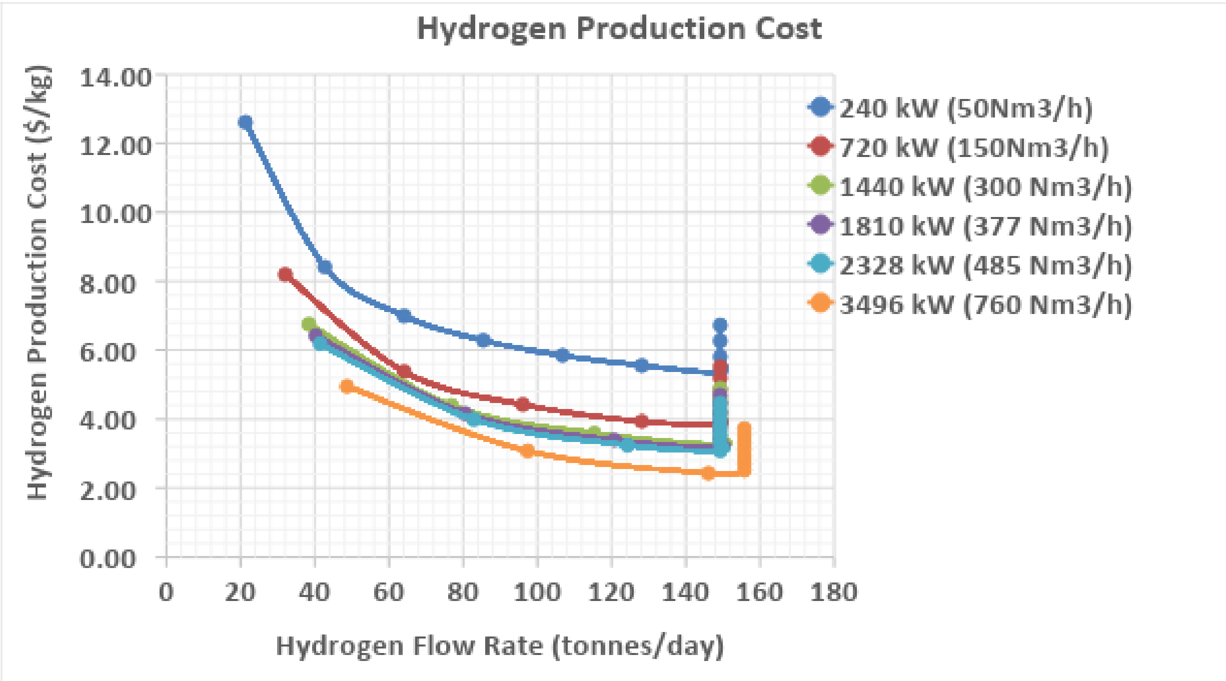


Figure 6: Hydrogen production costs

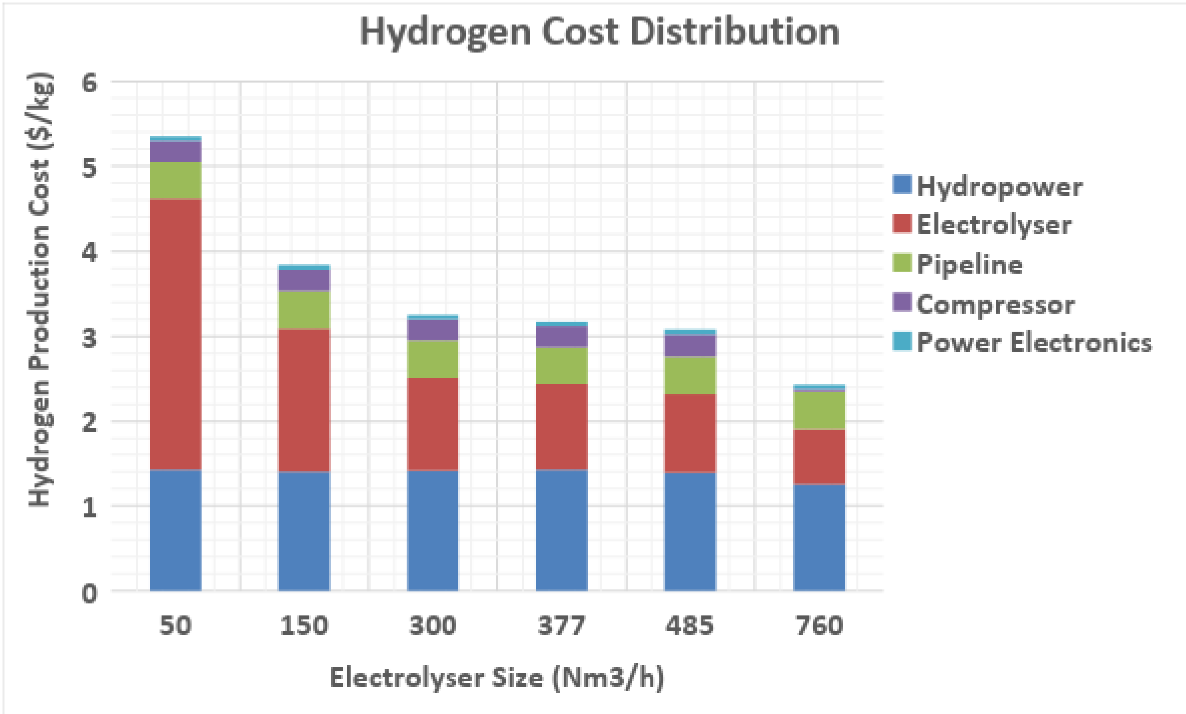


Figure 7: Hydrogen cost distribution

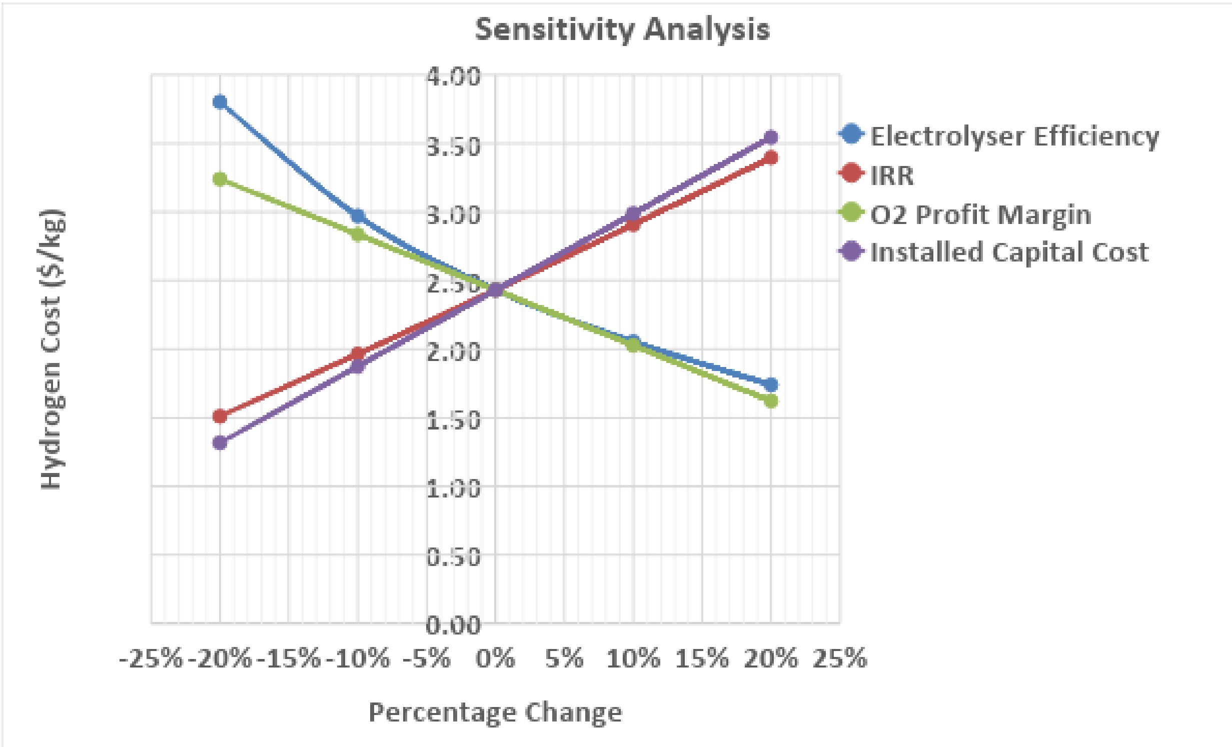


Figure 8: Hydrogen production costs - Sensitivities

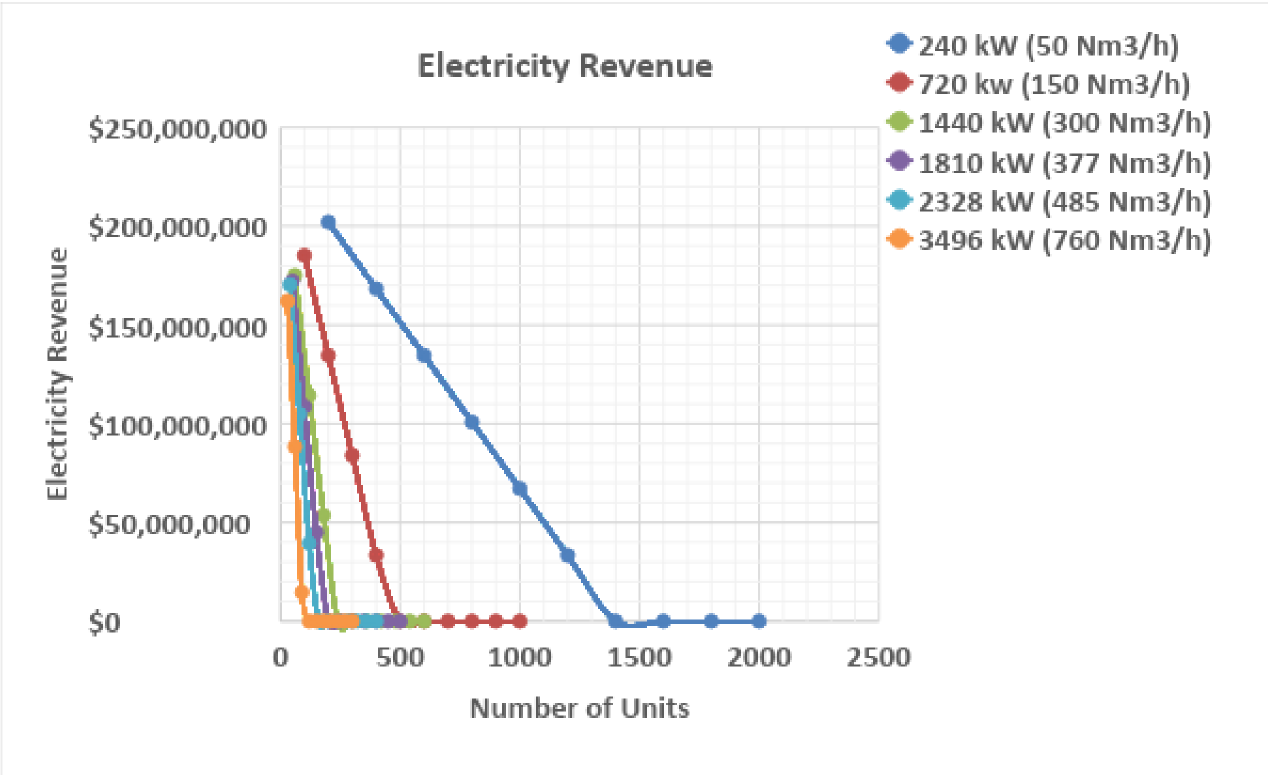


Figure 9: Energy sold to the electrical grid -Electricity revenue

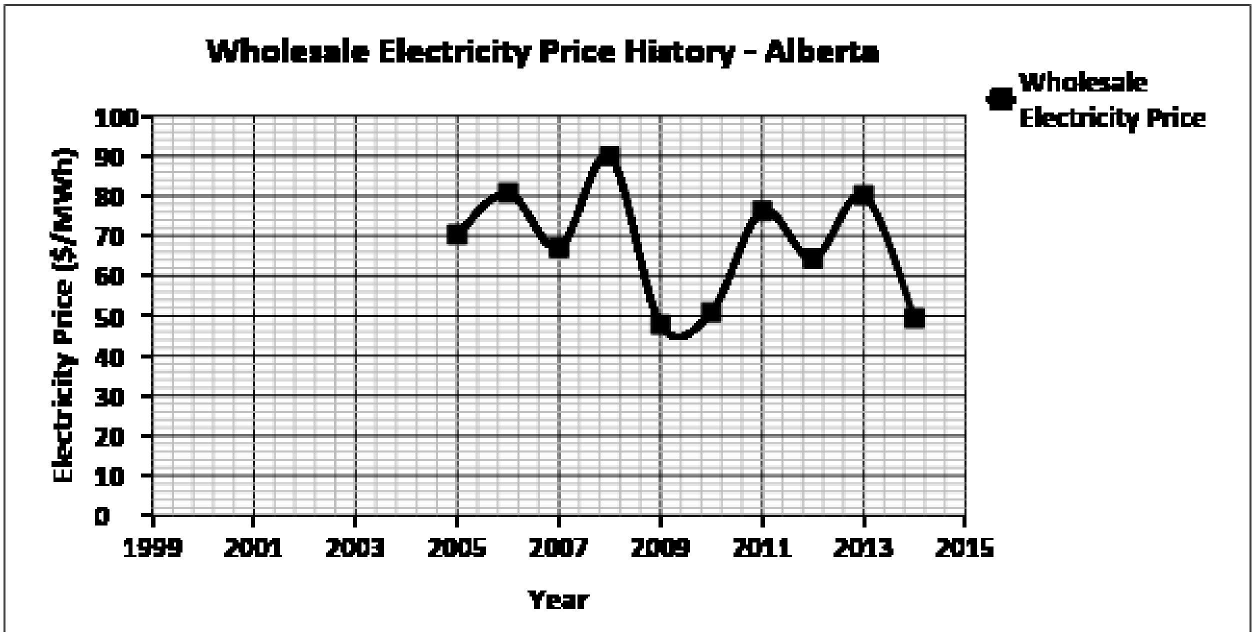


Figure 10: Alberta wholesale electricity (pool) price history: 2005 -2014 [47]

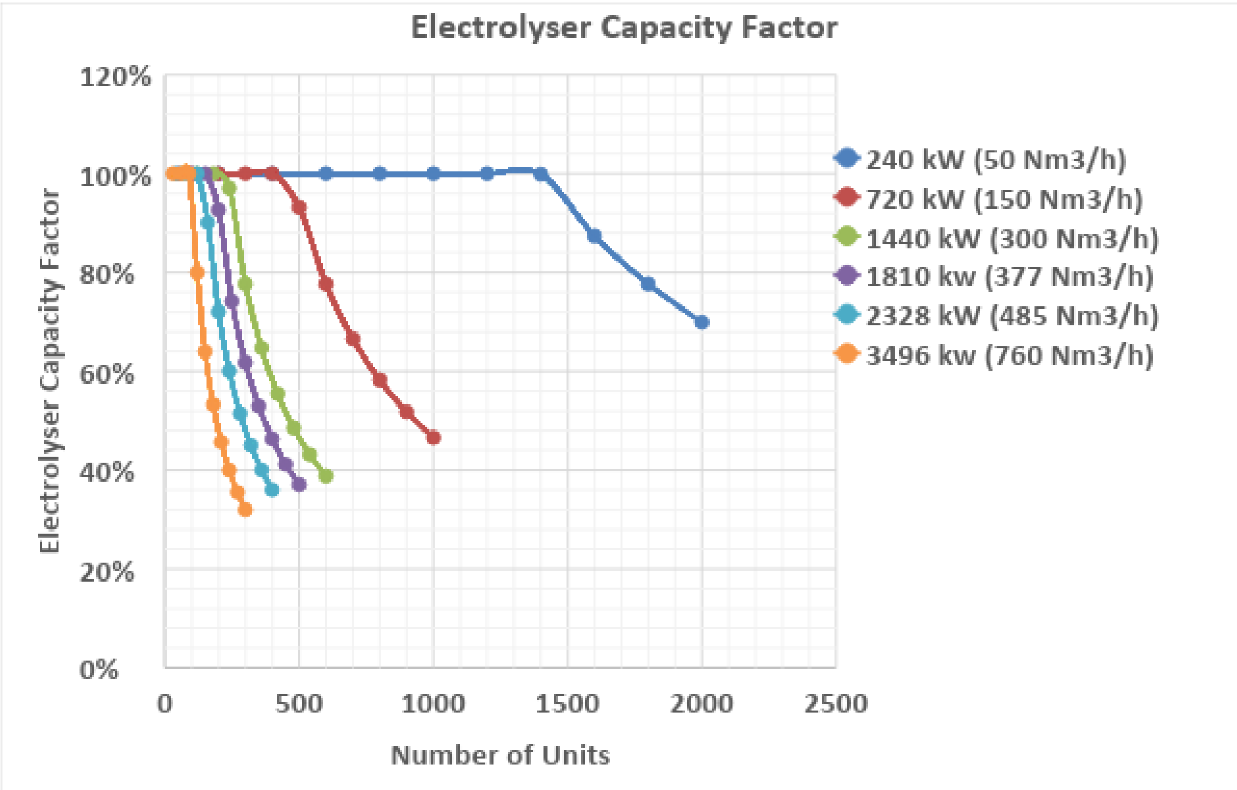


Figure 11: Electrolyser capacity factor

Table 1: Grid-connected hydropower capacity in Alberta as of 2011 [45]

Hydropower Plant Name	**Plant Capacity (MW)**
Brazeau	355
Bighorn	120
Spray	103
Ghost	51
Rundle	50
Cascade	36
Oldman River	32
Kananaskis	19
Raymond Reservoir	18
Barrier	13
Taylor	13
Chin Reservoir Station	11
Drop (4,5 & 6)	7
Inter Lakes Resevoir	5
Belly River	3
Waterton	3
St. Mary	2
TOTAL	**891**

Table 2: Electrolyzer size range [52, 53]

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 pressur (bar)
Norsk Hydro Atmospheric Type No. 5010 (5150 Amp DC) [52]	0[a]	50	4.8[b]	72.4	240	1
Norsk Hydro Atmospheric Type No. 5020 (5150 Amp DC) [52]	50	150	4.8[b]	72.4	720	1
Norsk Hydro Atmospheric Type No. 5030 (5150 Amp DC) [52]	150	300	4.8[b]	72.4	1440	1
Norsk Hydro Atmospheric Type No. 5040 (4000 Amp DC) [52]	300	377	4.8[b]	72.4	1810	1
Norsk Hydro Atmospheric Type No. 5040 (5150 Amp DC) [52]	300	485	4.8[b]	72.4	2328	1
Industrie Haute Technologie (IHT) Type S-556 [53]	190	760	4.9[b,c]	70.8	3496	30

[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[52].

[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).

Table 3: Hydropower capital and auxiliary plant costs.

Cost components	Values	Sources/Comments
Hydropower installed capital cost ($/kW)	4000	The range of installed capital cost specified for Canada by the International Renewable Energy Agency (IRENA) [56], ranges from $811 - $4870/kW. Alberta is likely to be closer to the upper end of this range. Moreover the specific capital cost utilized in this paper falls within the range of recent capital cost estimates for greenfield hydropower projects in Canada (see Table 4).
Plant power electronics cost ($/kW) (including rectifier and control unit cost)	35	Estimated relative to the cost specified for a 1GW wind-hydrogen plant [57].
Electrolyser labour and installation costs ($)	Function of electrolyser size.	10 % of electrolyser capital cost.
Electrolyser O&M cost ($/kW/yr)	18.4	[58]
Electrolyser cell stack replacement cost	Function of electrolyser size.	30% of electrolyser capital cost [59].
Hydropower O&M cost ($/yr)	2.6 % of total installed capital cost	Based on values specified by [46]
Pincher creek water cost ($/m3)	0.99	[28]
Hydropower plant life (yrs)	40	A conservative estimate of the plant life time is adopted in this study.
Electrolyser service life (yrs)	10	[59, 60].
Inverter service life (yrs)	10	[61]
Control unit service life (yrs)	10	[28]

Table 4: Recent Canadian greenfield hydropower capital costs estimates [16, 62-64].

Name	Location	Cost ($ Millions)	Capacity (MW)	Installed Cost ($/kW)	Construction Activity
Site C [62]	British Columbia	8,775	1100	7977	In progress
Romaine Complex A [16, 63]	Quebec	6,500	1550	4193	In progress
Lower Churchill [16, 64]	Labrador	6,200	3000	2067	In progress