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Article

Integration of Wind Energy, Hydrogen and Natural Gas Pipeline Systems to Meet Community and Transportation Energy Needs: A Parametric Study

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Abstract: The potential benefits are examined of the "Power-to-Gas" (P2G) scheme to utilize excess wind power capacity by generating hydrogen (or potentially methane) for use in the natural gas distribution grid. A parametric analysis is used to determine the feasibility and size of systems producing hydrogen that would be injected into the natural gas grid. Specifically, wind farms located in southwestern Ontario, Canada are considered. Infrastructure requirements, wind farm size, pipeline capacity, geographical dispersion, hydrogen production rate, capital and operating costs are used as performance measures. The model takes into account the potential production rate of hydrogen and the rate that it can be injected into the local gas grid. "Straw man" systems are examined, centered on a wind farm size of 100 MW integrating a 16-MW capacity electrolysis system typically producing 4700 kg of hydrogen per day.

Keywords: hydrogen; natural gas; wind turbine; wind farm; NG pipeline; community; transportation; parametric study; straw man system

1. Introduction

Wind turbines (WTs), often clustered into wind farms, have proliferated in Ontario and many other regions across North America and in other countries in recent years for a variety of economic and environmental reasons. While potentially offering significant promise as a contributor to energy systems in the future, wind power has several problems. One is that it is highly intermittent, subject to significant changes in the level of power production over relatively short periods of time. Another problem is that the moment-by-moment supply of wind energy generally does not match to the varying demand of the power grid. These factors lead to times when the grid must either: (1) accept power from wind farms at a loss; (2) curtail production from less costly sources of power; or (3) not accept wind energy all together.

Several schemes have been proposed to mitigate these problems in order to improve the economic and environmental benefits of wind power installations. These schemes typically involve either applying the wind power to an immediate, local ("inside the gate") use, storing it in some form for later deployment or converting it to a form that is needed by other markets.

One storage concept is to use electrolysers to store "excess" wind generated electricity as hydrogen. An electrolyser is a device that uses electricity to split water molecules into oxygen and hydrogen. These gases are then stored for a variety of uses, such as feed stocks for industrial applications, or recombining them to regenerate electricity at a later time. Here, we consider the opportunities associated with the concept of injecting wind-generated hydrogen into the natural gas distribution grid, essentially increasing the proportion of hydrogen that naturally occurs in natural gas. The concept of "wind to electricity to hydrogen to natural gas" is often referred to as "Power-to-Gas" (P2G).

P2G has the advantage of avoiding the need for large and expensive means to store or transport hydrogen; rather, it provides a readily available and potentially cost-effective means to take the product to market. Below a certain concentration (~20% hydrogen in natural gas) [1], hydrogen has no adverse effect on the combustion characteristics of natural gas, and in fact, its addition results in a cleaner burning fuel. P2G also relies on wind farms that are in close proximity to an adequate and appropriate natural gas pipeline infrastructure; otherwise, high transportation costs may be incurred. An economic disadvantage of P2G can be that it effectively sets the monetary value of hydrogen equal to that of natural gas on a volumetric basis.

Benefits of Power-to-Gas (P2G) with Wind Turbine (WT) Systems

It is anticipated that a P2G system may provide economic and operational benefits to WT system operators and others. Challenges, such as curtailing greenhouse gas production, stewardship of non-renewable fuel resources and energy security, have driven the need to develop alternative sources of energy that are local, sustainable and reduce the impact on the environment. Wind power is considered to be plentiful, renewable, widely distributed, clean, zero greenhouse gas emitting during operation and efficient in terms of land use [2]. Generally, its effects on the environment are usually less problematic than those from other power sources.

Hydrogen as an energy carrier, and as a means of energy storage, has the potential to increase the penetration and efficiency of sustainable energy sources, such as wind and solar energy. The use of hydrogen can enable the large-scale use of hydro, solar, wind and geothermal energy, both for stationary and transportation energy systems. Preliminary studies have shown that it is possible to transport a mixture of natural gas and hydrogen through the existing natural gas network without pipeline modifications, as long as the mass fraction of hydrogen remains sufficiently low [3].

In this article, we consider the opportunities associated with the concepts of injecting hydrogen into the natural gas pipeline. By injecting hydrogen from surplus renewable electricity into the natural gas pipeline, the enormous transportation and storage capacity of the existing infrastructure can be used directly. Such an approach can make an important contribution to the transportation and storage of surplus or non-transportable renewable electricity. Injecting hydrogen into the natural gas network can contribute significantly to solving the problem of transporting and storing surplus electricity generated from renewable resources.

It should be noted that there are other ways the hydrogen could be used. For instance, the hydrogen could be combined with CO or CO_2 to produce methane (see Section 2.7), or it could be combined with nitrogen to produce ammonia. The hydrogen could also be delivered to merchant gas suppliers or vehicle fuelling stations via tube trailers or through a dedicated hydrogen pipeline, as outlined in Section 2.4. These ideas will be reviewed in this article, but not in great detail, as the main focus is the idea of the power-to-gas approach and the benefits of such a system.

The concept of linking wind energy and hydrogen production using electrolysis is specifically examined in this article. Additionally, the electrolysis capacity associated with a wind farm size is compared to determine the daily maximum hydrogen production. A sensitivity analysis is performed for determining the variability costs associated with wind farm and electrolysis size. A simple payback period calculation is performed to determine the parameters that impact the outcome of the analysis.

2. Background

2.1. Wind Farms

Wind turbine designs are generally classified by the structure of the rotor and its location in the airflow [4]. The two main types of wind turbine are horizontal axis and vertical axis, with the most common configuration being the horizontal axis turbine. The rotor of a horizontal axis wind turbine rotates around a horizontal axis, parallel to the wind direction. The blades resemble propellers and are arranged rigidly in a plane that is always oriented perpendicular to the wind [5].

Until recently, the costs required for the maintenance of a wind turbine were one of the largest uncertainties in the calculation of the long-term economics of wind power generation. The early stages of the introduction of a new technology are often burdened by numerous technical breakdowns and failures. However, wind turbines of the latest generation already achieve a degree of reliability that is equal to that of comparable technologies [6].

The installed capacity of wind turbines (WTs) has increased significantly since 2000. A study by the Canadian Wind Energy Association (CANWEA) in June 2013, indicated that the total capacity of WTs in Ontario is 2043.2 MW [7]. A wind farm is a group of WTs located in relatively close proximity, usually with a common tie-in point to control electrical flow to the grid. A large wind farm (~200 MW) may consist of several hundred individual wind turbines and cover an extended area;

however, the land between the turbines may be used for agricultural or other purposes. The full map of wind farms in southwestern Ontario as published by Ontario's Independent Electricity System Operator as of February 2013 [8], can be accessed via the reference link.

While WTs offer the potential to deliver green energy for the future, they do have some inherent problems. One issue is that the driving force—the wind—is highly intermittent. The total power produced by a wind farm may change over relatively short periods of time. Furthermore, occasionally, there are times when the energy production rate exceeds the demand on the grid or the grid's capacity to transmit it. These factors lead to times when: (1) the grid can only accept power from wind farms at a loss; (2) production from other less costly sources of power must be curtailed; or (3) the energy must be foregone altogether.

Another inherent problem with wind turbines or wind farms has been their associated noise level. Since the early 1980s, wind turbine manufacturers have made significant efforts to reduce these noise levels. Efforts include decreased aerodynamic noise levels, regardless of turbine output capacity, by sharpening the trailing edges of the rotor blades and using new tip shapes. Mechanical noises of larger systems have been reduced by isolating the gearboxes from the nacelles and installing sound-deadening insulation. These techniques have made newer wind turbines significantly quieter [9].

Despite these inherent problems, over the last decade, the Canadian wind-energy sector has evolved from a scattering of individual installations to a quickly growing energy source. While this growth has been supported and encouraged by various levels of government across Canada, many of the projects have experienced extensive cost overruns, delays and, in some cases, cancellation related to confusing or unclear regulatory requirements, which differ considerably throughout the various Canadian jurisdictions.

The majority of the relevant codes and standards relate to the structural, mechanical, electrical and operating characteristics of wind turbines. These are the subject areas that have been addressed by the Canadian Standards Association (CSA) since the 1980s, when the following National Standards of Canada pertaining to wind energy conversion systems (WECS) were developed [10]:

- CAN/CSA-F416-87, Wind Energy Conversion Systems (WECS): Safety, Design and Operation Criteria;
- CAN/CSA-F417-M91, Wind Energy Conversion Systems (WECS): Performance;
- CAN/CSA-F429-M90, Recommended Practice for the Installation of Wind Energy Conversion Systems; and
- CAN/CSA-F418-M91, Wind Energy Conversion Systems (WECS): Interconnection to the Electric Utility.

It is expected that the five new Wind Turbine Generator Systems (WTGS) Standards will be adopted as the National Standards of Canada:

- CAN/CSA-C61400-11, Wind Turbine Generator Systems, Part 11: Acoustic Noise Measurement Techniques;
- CAN/CSA-C61400-12-1, Wind Turbines, Part 12-1: Power Performance Measurements of Electricity Producing Wind Turbines;
- CAN/CSA-C61400-24, Wind Turbine Generator Systems, Part 24: Lightning Protection;
- CAN/CSA-C61400-1, Wind Turbines, Part 1: Design Requirements;
- CAN/CSA-C61400-2, Wind Turbines, Part 2: Design Requirements for Small Wind Turbines.

2.2. Mitigation Strategies

Several schemes have been proposed to mitigate the problems of intermittency and excess energy associated with wind farms in order to improve their economic and environmental benefits. These schemes typically involve either directing the wind power to an immediate, local ("inside the gate") use, storing it in some form for later deployment or converting it to a form that can be directed to other markets.

There are several methods for directly or indirectly storing wind energy, such as thermal energy storage [11], mechanical energy storage (such as pumped water or compressed air) and chemical energy storage (such as hydrogen and batteries). Although the conventional battery appears to provide a readily available means of energy storage, it is problematic for grid-scale electricity storage. At grid scales, batteries are bulky, incur the expense of maintaining a large battery room, require sophisticated charge/discharge monitoring systems and require thermal analysis and management to provide optimal battery life. Nevertheless, storing a limited amount of electrical power in batteries for short periods and then using it on-site can be beneficial for on-site building or automotive loads.

2.3. Hydrogen

Another means of storing electricity is to use it to drive water electrolysis to generate hydrogen. This means of storage provides a great deal of flexibility. For instance, the hydrogen can be converted back into electricity via an internal combustion engine (ICE) or a fuel cell (FC), used either immediately or later, stored locally or shipped to an off-site location; and used in a wide variety of applications.

In electrolysis, water (H_2O) is split into oxygen (O_2) and hydrogen (H_2), by passing an electric current through it [12]. Polymer electrolyte membrane (PEM) electrolysis provides a suitable means of generating hydrogen from renewable energy sources, due to its fast response time, large operational range, relatively high efficiency and the high purity of the gas generated (99.999%).

A full electrolysis system requires a source of deionised water, temporary electrical storage, storage vessels and compressors. PEM electrolysers typically generate hydrogen at low pressures. High pressure electrolysis (HPE) requires more energy, but reduces the need for compression. The hydrogen produced may be stored in the immediate area or be transported to off-site locations that have a use for hydrogen. In this case, the local storage space and cost may be reduced, but a transport system would become necessary.

2.4. Hydrogen Markets and Transportation Options

It is desirable to use the hydrogen produced in high value applications, such as vehicle fuel (in ICE or fuel cell vehicles) or as a feedstock in industrial applications, such as food oil hydrogenation, gas turbine cooling or steel making [13]. Most of these applications require a means to transport the hydrogen to the point of use.

Dedicated distribution pipelines for hydrogen are typically much more costly than natural gas pipelines. Some sources [14] estimate a cost of $1M/inch-mile as compared to the $300,000/inch-mile [15] for natural gas pipelines. Creating a new pipeline for hydrogen may be too expensive given the current market; however, a dedicated network of hydrogen pipelines may become feasible if and when hydrogen becomes more widely used as an energy carrier.

Another means of transporting the hydrogen to market is via tube trailers (sometimes referred to as a pipeline on wheels). This method has recently been used successfully for transporting natural gas to off-grid industrial locations. Several projects have been undertaken by Change Energy Services (CES) over the last three years, particularly in maritime Canada, where the natural gas pipeline grid is relatively new and remote from much of the pre-existing industry. JD Irving, Heritage Gas and Irving Oil have used this method to reduce energy costs and environmental emissions for customers requiring process heat for food processing, pulp paper mills and other applications. An economic analysis conducted by CES for these customers indicates that, in order to justify the capital cost of the compression, trailer and end-use decanting facilities, loads (in aggregate) on the order of 2000 scfm of natural gas (equivalent to approximately 7400 kg of H_2 per day) are required [16]. This much hydrogen could be supported by a wind farm of about 130 MW, but it would take some time to develop a market for this quantity of hydrogen (equivalent to about 7000 hydrogen cars or 600 hydrogen buses).

Another option for using the hydrogen is the utilization of the natural gas pipeline grid currently in place in most communities. This grid may offer a viable option by utilizing the hydrogen to augment the natural gas supply (essentially, the P2G solution) or as a means to transport it to a downstream separation facility. Downstream separation was explored in the NaturalHY project [17], as discussed later in this report. The main objective of NaturalHY is to prepare European countries for the hydrogen economy by identifying and removing potential barriers regarding the introduction of hydrogen into society, using the existing natural gas system.

Hydrogen produced by wind energy can also be converted to methane through a "methanation" process. Methanation processes are physical-chemical processes that generate methane from a mixture of various gases; the main components are carbon monoxide and hydrogen [18]. In this way, the wind energy can be captured in a form that can be exported to other markets as natural gas.

2.5. Power-to-Gas (P2G)

The concept of P2G proposes that "excess" wind energy be captured by using it to produce hydrogen, which can either be taken to market or used to augment the natural gas supply.

A P2G unit receives its power from a nearby wind farm. The power drives the electrolysis equipment that transforms water into hydrogen, which is injected into the regional gas transmission system. The hydrogen becomes part of the natural gas mix and can be used to generate power or heat.

A recent article [19] reported on the experience of E.ON. E.ON is a European holding company based in Düsseldorf, North Rhine-Westphalia, Germany. E.ON runs one of the world's largest investor-owned electric utility services. The article reported on the injection of hydrogen produced with surplus wind energy into the natural gas system located in Falkenhagen, Germany [20]. The region's wind farms already frequently produce more electricity than the local grid can handle. During a three-hour test, the unit produced 160 cubic meters (5650 cubic feet) of hydrogen, which was injected into the natural gas pipeline system. This marked the first time E.ON successfully implemented all stages of the process, from receiving electricity to injecting hydrogen.

E.ON's P2G facility in Falkenhagen, Germany, uses wind power and an electrolyser provided by Hydrogenics to split water molecules into hydrogen and oxygen. The hydrogen is injected into the existing regional natural gas transmission system. The hydrogen becomes part of the natural gas mix used in a variety of applications, including space heating, industrial processes, mobility and power generation. The facility's electrolyser, which has a capacity of two megawatts, is capable of producing up to 360 cubic meters of hydrogen per hour [21].

Codes, standards and regulation development are required for interface systems and hydrogen handling systems appropriate for this scale of operation. While many of the technologies are mature at certain scales, there will no doubt be technology rollouts and reliability issues encountered as systems are scaled up and interface systems are developed.

2.6. Mixing Hydrogen with Natural Gas and Implications for Infrastructure

In examining a P2G delivery system's suitability for hydrogen, there is a need first to investigate the extent to which existing assets, including the existing wind farm and natural gas pipeline infrastructure, can be used.

An existing natural gas system generally offers the following advantages:

- It is in place and available immediately.
- It is well-established with existing grid management and operation strategies.
- It is widely spread out and interconnected.
- It has very high capacity, e.g., nearly three billion cubic feet per day in Ontario and Quebec [22].
- It has well-established safety procedures and an excellent safety record, based on a well-developed maintenance and control structure.
- It has broad acceptance by the public.

Existing natural gas transmission, distribution and end-use systems may be used, with suitable adjustments, for many mixtures of natural gas and hydrogen [23].

Hydrogen-enriched natural gas (HENG) is a mixture of hydrogen and natural gas. In theory, the two can be mixed in any proportion, but HENG typically has 10 to 20 percent of hydrogen by volume. At these concentrations, HENG is generally compatible with existing natural gas transmission and distribution infrastructure, as well as end-use equipment. Moreover, codes and standards in many jurisdictions treat HENG with less than 20 percent hydrogen the same as natural gas. This can facilitate the initial deployment of HENG into many gas networks.

HENG offers important potential emissions and efficiency benefits, compared to natural gas. [24]. HENG enhances combustion and reduces CO_2 emission from natural gas [25] and reduces emissions of pollutants, such as nitrogen oxide (NOx), carbon monoxide (CO) and unburned methane and other hydrocarbons. HENG can also improve the fuel efficiency of gas-fired combustion in boilers, engines and turbines, while still using existing natural gas delivery infrastructure and end-use equipment [25].

Identifying the conditions under which hydrogen can be added without unacceptable consequences to natural gas, and the development of devices for hydrogen separation from a mixture, was an important part of the NATURALHY project [17]. The aims of NATURALHY were to test all the critical components of a system in which hydrogen was added to an existing natural gas network. NATURALHY also examined innovative technologies for separating the transmitted hydrogen for utilisation at end-user sites [17].

Several studies have attempted to determine the appropriate mixture for HENG:

(a) In the case of the E.ON project, it was shown that up to 10% hydrogen by volume can be injected into the pipeline [19].
(b) Other studies show that depending on the pipe material, only up to 6% is allowable [26].
(c) In ICEs, the addition of a small amount of hydrogen to natural gas (5%–30% by volume) leads to many advantages, due to physical and chemical properties [27].
(d) Below about 20% of hydrogen in natural gas, hydrogen has no adverse effect on natural gas combustion characteristics and renders the fuel cleaner burning [1].

In summary, the range of 5%–20% hydrogen in natural gas by volume in a pipeline appears to be feasible. However, for safety reasons, when considering natural gas pipeline material embrittlement and unknown end-user applications, this study considers an upper limit of 5% hydrogen by volume.

2.7. Methanation

Another method of injecting hydrogen into the natural gas pipeline that avoids material compatibility issues is to methanize the hydrogen prior to injecting it. Methanized hydrogen is also referred to as synthetic (or substitute) natural gas (SNG) [28].

Methanation is a physical-chemical process to generate methane from a mixture of various gases [29]. The main components required are carbon monoxide and hydrogen. The main chemical process in methanation (also known as the Sabatier reaction) is as follows:

$$CO + 3H_2 \rightarrow CH_4 + H_2O \quad (1)$$

In the methanation reaction, CO and H_2 are converted to CH_4 and H_2O in a fixed bed catalytic reactor. Since methanation is highly exothermic, the increase in temperature is controlled by recycling the product gas or by using a series of reactors. Steam is added to the reaction to avoid coke formation in the reactor. The steam is then removed from the product gases by condensation [29].

A methanation facility requires water, process heat and cooling systems and a source of CO (or CO_2). As an example the Sabatier reaction process converts H_2 and CO_2 to SNG with water as a by-product [30]. One example of SNG production is the SolarFuel GmbH plant in Germany [31]. SolarFuel, also known as ETOGAS GmbH (a sustainable energy company based in Germany), in collaboration with German research institutes, has successfully developed a method of using electricity to produce SNG using the surrounding air as a source of CO_2. ETOGAS has built and run a successful test operating an alpha plant since 2009, which uses an electric load of 25 kW with an overall power-to-gas efficiency of 40% [32]. The ETOGAS SNG production plant utilizes an electrolysis reactor and a methanation reactor. The proposed Beta plant will use an Econamine FG Plus CO_2 capture process (a process developed and commercialized by Fluor) to supply the CO_2 needed for methanation [33].

3. Problem Formulation and Analysis

3.1. Straw Man Model

A model was developed that determines the capital and operating cost inputs, as well as the energy and resource inputs required to implement a viable, real-world Power-to-Gas (P2G) system. The model considers and incorporates system input limitations, system losses and system output requirements. The model determines the net cost of hydrogen as an output. This cost may be used as an input to various cost recovery mechanisms, and simple payback periods may be determined.

The reporting of sensitivity analyses in a systematic review may best be done by producing a summary table. Table 1 below provides a list of parameters used to model the system for the purpose of this study. These parameters are used firstly as inputs to the cost and revenue model and, secondly, for the sensitivity analysis. The sensitivity analysis is used to identify which parameters have the greatest impact on the outcomes of interest. Each parameter is represented by the letter "P" followed by a numerical value.

Table 1. Parameters used in the analyses.

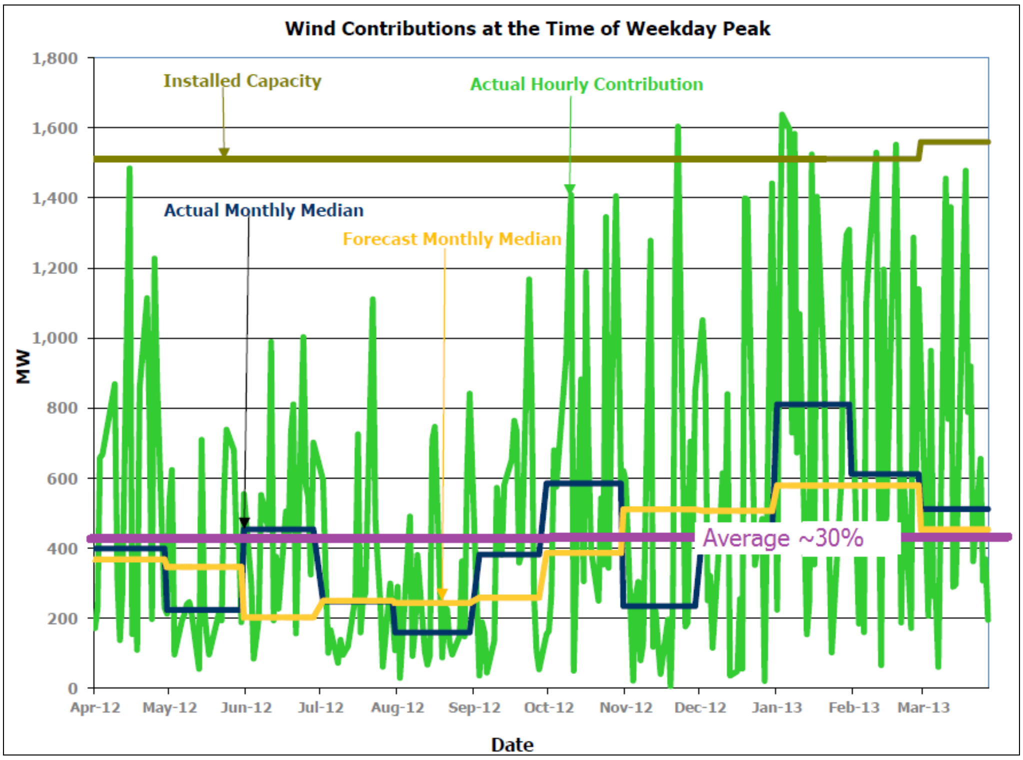
Parameter	Description	Units	Min.	Max.	Normal
P1	Wind farm (WF) size	MW	25	200	variable
P2	Maximum feed factor (input power to electrolyser as a % of WF size)	%	25	100	50
P3	Average wind energy produced by WF (as a % of total size)	%	10	60	30
P4	Battery feed rate (to provide short-term operational requirements of the electrolyser, as a % of electrolyser size)	%	10	100	30
P5	Electrolyser full load supply duration	min	10	60	30
P6	Battery charge range (% max charge–% min charge)	%	50	90	70
P7	Battery efficiency	%	80	95	90
P8	Battery utilization (percentage of daily energy produced by WF)	%	5	30	25
P9	WF controller efficiency	%	90	99	98
P10	WF transformer efficiency	%	80	98	95
P11	Electrolyser rectifier efficiency	%	70	95	85
P12	Electrolyser hydrogen losses from production	%	5	20	10
P13	Hydrogen storage losses	%	0	5	2
P14	Power to run hydrogen handling and metering system	kWh/day	5	50	12
P15	Power to run hydrogen dispensing unit	kWh/day	5	50	12
P16	Power to run water management system	kWh/m^3 of H_2	0.0001	0.001	0.0005
P17	Cost of water	\$/m^3	0.0001	0.001	0.0005
P18	Electrolyser maintenance cost	\$/kg	0.00001	0.0005	0.0001
P19	Compressor, purification and storage system maintenance cost	\$/kg of H_2	0.01	0.05	0.03
P20	Water management system maintenance cost	\$/m^3	0.00001	0.0005	0.0001
P21	Electricity cost	\$/kWh	0	0.12	0.00
P22	Natural gas cost	\$/m^3	0	0.325	0.12

In the columns in Table 1, "min" represents the lowest value expected for the parameter, "max" the highest value expected and "normal" the expected typical value. The latter is used as the baseline value in the present analysis. For example, parameter "P2" is the maximum feed factor (representing the highest input to the electrolyser as a percentage of rated wind farm output). P2 is assigned a minimum value of 25% and a maximum value of 100%, with a normal value of 50%. Similarly, "P3" represents the average wind energy provided by the wind farm (as a percentage of full operation at name plate rating). This parameter has a minimum value of 10%; this minimum value refers to the lowest wind energy produced by the wind farm as a percentage of the wind farm capacity. It has a maximum value of 60%, referring to the highest wind energy produced by the wind farm as a percentage of the wind farm capacity. Based on information gathered by the Independent Electricity System Operator (IESO) [8], the actual capacity over the year as measured is nearly 30% of the total wind farm capacity. Therefore, the normal value used is 30%.

For parameters P2, P4, P8, P4, P15, P16, P21 and P22, a range was established that was broad enough to examine realistic economic feasibilities (for P21 and P22, we allow for the system owner to supply excess electricity at zero cost). The parameter, P5, range is an estimate based on IESO data, and P6 values are based on typical commercially available battery charge management systems. Parameters P9, P10, P11, P12, P13, P18, P19 and P20 were assigned ranges based on equipment and experience from previous Change Energy Services (CES) projects.

Figure 1 shows the actual and median monthly contribution to the electrical power grid by wind farms in Ontario, based on an installed wind turbine capacity in southwestern Ontario of ~1500 MW [8]; the data from this figure is summarized in Table 2). The actual production over the year as measured by the Independent Electricity System Operator [8] is approximately 30% of the total installed capacity. For this study, we have used an average value of 30% for calculations.

Figure 1. Overall wind energy contributions from installed wind farms in Ontario [8].



Notes: The commercially operable capacity does not include the commissioning unit. Therefore, actual hourly contributions may exceed commercial capability. "Installed capacity" means a full name plate rating of installed and connected wind farms. The term "Wind Contribution" refers to the amount of power supplied to the grid from the wind farms.

Table 2. Actual monthly median wind power produced [8].

Date	Actual monthly median power level (MW)
April 2012	400
May 2012	220
June 2012	450
July 2012	250
August 2012	180
September 2012	390
October 2012	590
November 2012	220
December 2012	440
January 2013	800
February 2013	600
March 2013	500
Average wind power generation level over the year	420
Total installed wind power generation capacity	1500
% of average wind power generation level compared to total installed wind power generation capacity	~30%

3.2. Sensitivity Analysis

A sensitivity analysis is used to examine which inputs most strongly influence the overall findings. While many inputs are clearly objective, some will be somewhat arbitrary. Sensitivity analysis helps identify which inputs require fine tuning.

Where sensitivity analysis identifies particular values or missing information that greatly influence the findings, recommendations for further study can be made. A sensitivity analysis examines how the output of a mathematical model or system varies according to the uncertainty of its inputs [34]. Sensitivity analysis can be useful for a range of purposes [35], including:

- Testing the robustness of the model's results;
- Understanding relationships between input and output variables in a model;
- Identifying model inputs that cause significant uncertainty in the output;
- Simplifying the model; inputs that have little or no effect can be removed.

Only three sizes of wind farm are considered for the sensitivity analysis in this study (25 MW, 100 MW and 200 MW). These sizes are used, as they represent the range of typical wind farms found in locations closest to the major natural gas pipelines in southwestern Ontario. The model developed for this study could also be used for other wind farm sizes that may be of interest.

Tornado charts are used for presenting the sensitivity analysis results. Tornado charts are a type of bar chart where the data parameters (categories) are listed vertically instead of the standard horizontal presentation. The parameters are ordered based on their total relative impact, with the parameter having the greatest impact (longest bar) appearing at the top of the chart. The resulting chart has a final visual look resembling a tornado; hence the name.

Tornado charts are useful for deterministic sensitivity analysis, comparing the relative importance of the parameters under consideration. For each parameter considered, an estimate for the minimum, normal and maximum value is made. The model is run with each variable at these three values, while all other parameters are held at their "normal" values [36]. This allows for testing the sensitivity associated with each parameter.

Here, two types of sensitivity analysis are examined: the system cost per wind farm size and the simple payback period per wind farm size. The parameters outlined in Table 1 are used for this analysis.

Simple payback period (SPP) refers to the length of time required to recover the initial investment as calculated from operating costs and revenues. SPP is the least precise of all capital budgeting methods, because the calculations in dollars are not adjusted for the time value of money [37]. However, SPP is often used as a tool for analysis, because it is easy to apply and understand and makes no assumptions about how a business may choose to allocate debt or equity capital or treat operating costs. A calculation of SPP is used with the tornado charts to determine the sensitivity associated with each parameter.

4. Results and Discussion

In this section, the parameters outlined in Table 1 are used to determine the rate of hydrogen production and the cost of the P2G system. The size of the electrolyser system is evaluated as follows:

$$\text{Electrolysis system size (ESS)} = \text{max energy available/24 h/day} \tag{2}$$

where the maximum energy available to the electrolyser is calculated by:

$$\text{Max energy available (MEA)} = (\text{P1})(\text{P2})(\text{P3})(24\text{ h/day}) \tag{3}$$

The rate of total hydrogen production per day is then determined from ESS and the known energy available from the wind farm. The energy efficiency of the water electrolysis process varies widely; reports suggest efficiencies of between 50%–80% [38,39]. These values refer only to the efficiency of converting electrical energy into hydrogen's chemical energy. Industrial electrolysers used in past CES projects have required an electrical energy input of 65–80 kWh/kg of hydrogen produced. A value of 70 kWh/kg of hydrogen has been used as a typical value in this study. The rate of hydrogen produced per hour is obtained as follows:

$$\text{Hydrogen produced per hour} = \text{EER}(1000)/(24 \times 70) \tag{4}$$

where EER is the electrolyser energy required and MEA is the maximum energy available in the system. The EER is calculated via the maximum energy available and subtracting the losses associated with the operation of the electrolyser.

$$\text{EER} = \text{MEA} - \text{MEA}(1\text{-P11}) - [\text{PPC} + \text{EE} + \text{PL}] \tag{5}$$

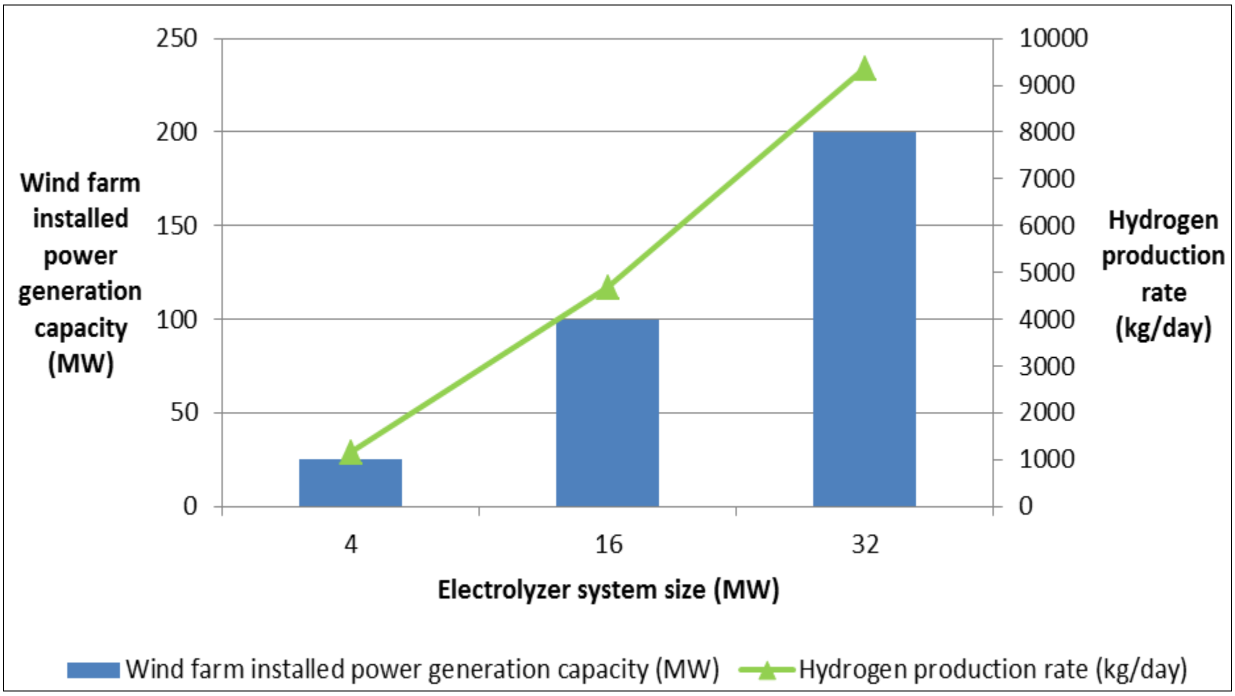
where PPC is parasitic power consumption, EE is equipment efficiency, P11 is the electrolyser rectifier efficiency and PL is product losses.

Electrolysis system sizes and the rates of hydrogen production derived by the model for various wind farm sizes are provided in Table 3. Figure 2 presents the results shown in Table 3 graphically; estimates of electrolyser size and H_2 produced per day can be made for other wind farm sizes from this graph.

Table 3. Result summary table from analysis.

Wind farm installed power generation capacity (MW)	Maximum energy available (MEA) (MWh/day)	Electrolysis system capacity (MW)	Daily rate of hydrogen production (kg/day)	Hourly rate of hydrogen production (kg/h)	Electrolyser energy consumption rate (EER) (MWh/day)
25	99	4	1157	48.2	81
100	396	16	4672	194.7	327
200	792	32	9360	389.9	655

Figure 2. Daily hydrogen production rate and electrolyser capacity *versus* wind farm installed power generation capacity.



4.1. System Costs and Sensitivity Analysis

The system cost is determined as follows:

$$\text{System cost} = \text{PMC} + \text{EC} + \text{H}_2\text{S} + \text{H}_2\text{D} + \text{ESC} \tag{6}$$

where PMC is the power module cost, EC is the electrolysis system cost, H_2S is the cost of hydrogen storage, H_2D is the cost of the hydrogen dispenser and ESC is the electrical storage cost. These terms can be expressed as follows:

$$\text{PMC} = \$250{,}000 + \$10{,}000(\text{ES}) \tag{7}$$

$$\text{EC} = \$1{,}200{,}000(\text{ES}) \tag{8}$$

$$\text{H}_2\text{S} = (\text{H}_2\text{P})(\$1200/\text{kg}) + \$335{,}000 \tag{9}$$

$$\text{H}_2\text{D} = \$190{,}000 \tag{10}$$

$$ESC = SC(1000)(BPS) \quad (11)$$

$$BPS = 30\%(ES)(P5)/60 \quad (12)$$

where BPS is battery pack size, P5 is the electrolyser full load supply, ES is the electrolyser size, H_2P is the hydrogen produced per day and SC is the storage (battery pack) cost. The value of SC is based on an estimate from a battery supply company. Note, the listed numerical cost values in Equations (7) to (12) are estimates used by Change Energy Services based on prior projects.

The simple payback period (SPP) used in the sensitivity analysis is calculated as follows:

$$SPP = \text{System cost/Net revenue per year} \quad (13)$$

$$\text{Net revenue per year} = NVH_2(365) \quad (14)$$

$$NVH_2 = VH_2 - OC \quad (15)$$

$$OC = CE(H_2P(70)) + H_2P(CMC) + EMC(H_2P) + WPMC(W) + P17(W) \quad (16)$$

$$VH_2 = (P22)(PH_2) \quad (17)$$

Here, SPP is the simple payback period, NVH_2 is the net value of hydrogen, VH_2 is the value of hydrogen, OC is the operating cost, CE is the cost of electricity ($/MW), CMC is the compressor maintenance cost ($/MW), EMC is the electrolyser maintenance cost ($/MW), WPMC is the water purification maintenance cost ($/MW), W is the amount of water used, P22 is the cost of natural gas ($/m^3) and PH_2 is the amount of hydrogen (m^3) injected into the natural gas pipeline. In this study, the hydrogen injected is based on the maximum of either the amount of the pipeline can accept (5% of the natural gas pipeline flow is considered based on previous studies [27]) or the amount of hydrogen the wind farm can produce. In most cases, this is dictated by wind farm size.

The sensitivity analysis is conducted using Equations (6) and (13) and the "Min", "normal", and "Max" values from Table 1. The "normal" outputs are obtained by inputting all the "normal" values into Equations (6) and (13). These values are used as the dividing point between the "Min" and "Max" values on the tornado charts. The equations are next evaluated based on each parameter's "Min" and "Max" value. The parameters are then sorted based on the absolute difference between the "Max" and Min" output values. The results are graphed with the highest difference value (or parameter with the greatest impact) at the top.

Figure 3 displays the tornado chart for a system associated with a 25-MW wind farm. In this chart, the "normal" system cost is $6,322,000, and the following parameters have the greatest impact on the overall system cost:

- P3, average energy produced by the wind farm;
- P2, maximum feed factor;
- P4, battery feed rate;
- P5, electrolyser full load supply duration;
- P6, battery charge range.

Figure 3. Twenty five megawatt wind farm system cost ($).

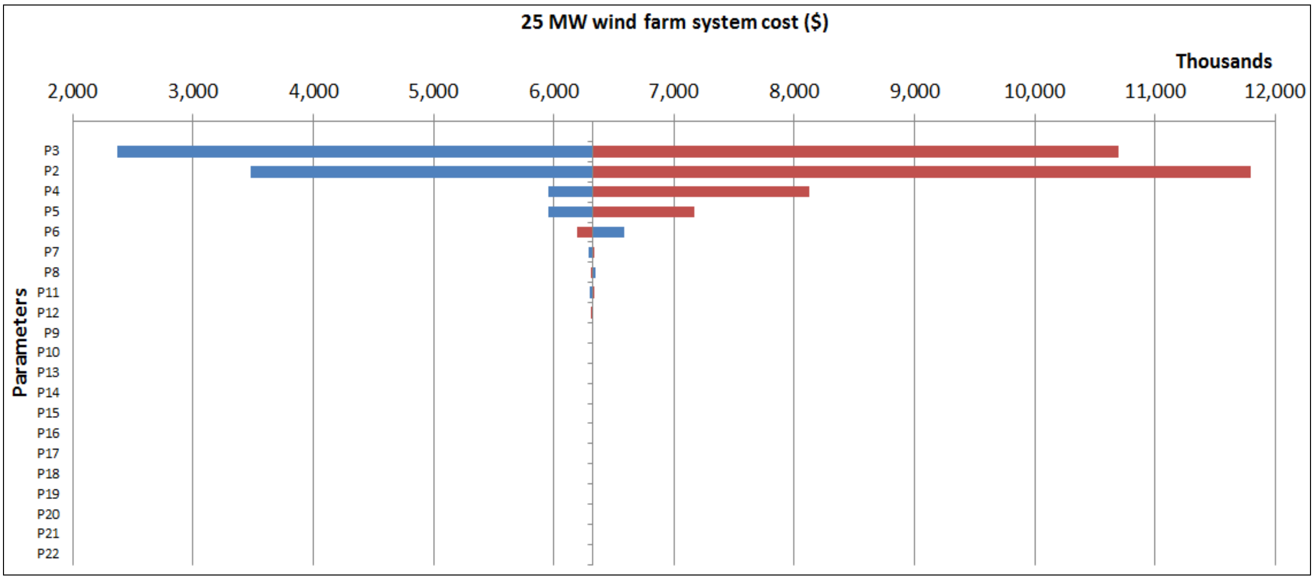


Figure 4 presents the tornado chart for a system associated with a 100-MW wind farm. The "normal" system cost in this case is on the order of $23,174,000.

Figure 4. One hundred megawatt wind farm system cost ($).

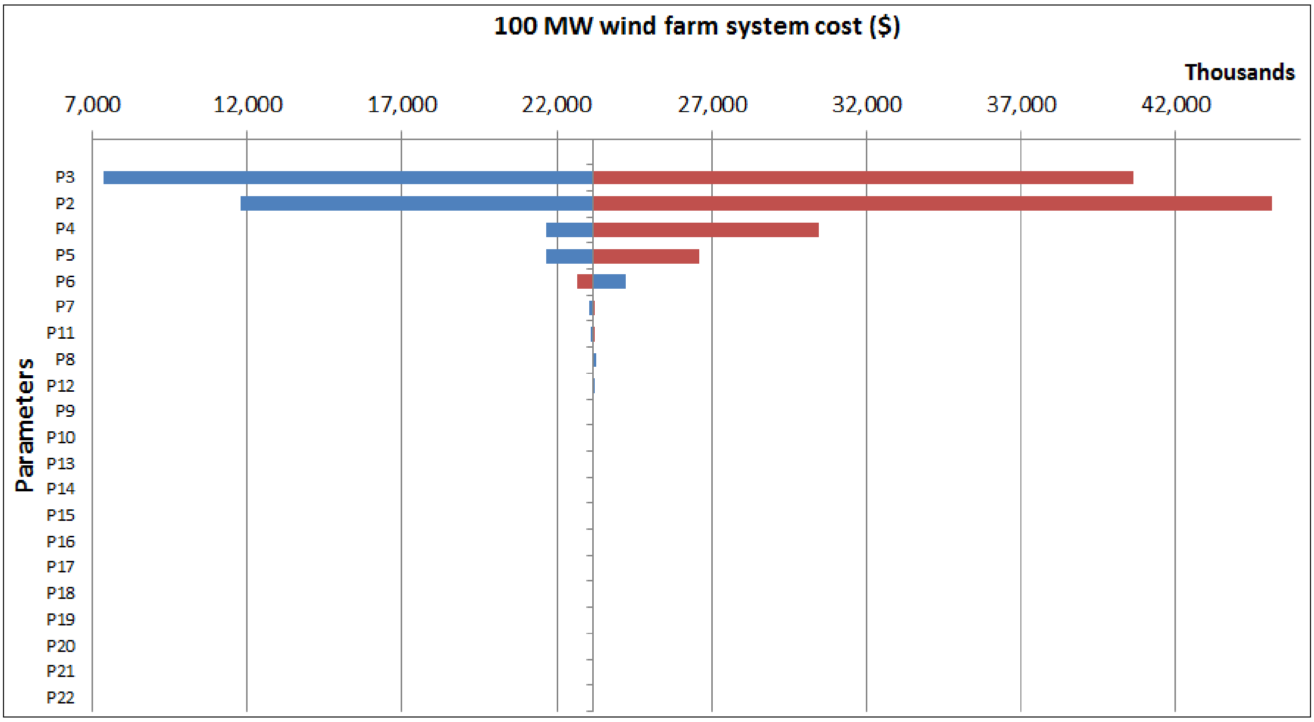


Figure 5 shows the tornado chart for a system associated with a 200-MW wind farm. The "normal" system cost is $45,639,000. Although prices vary for each wind farm, there is little variability in the relative impact of the parameters. This is because the total system cost is dominated by the cost of the electrolyser and battery packs. These values are relatively linear with respect to the wind farm size until the wind farm size drops below 5 MW.

Figure 5. Two hundred megawatt wind farm system cost ($).

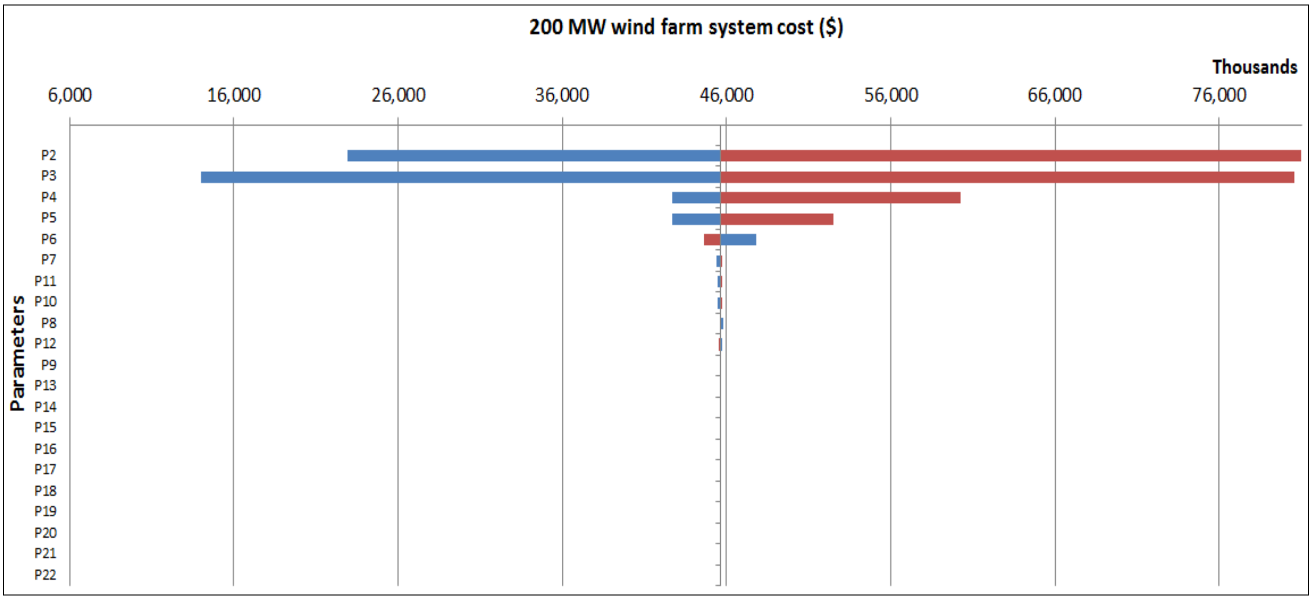
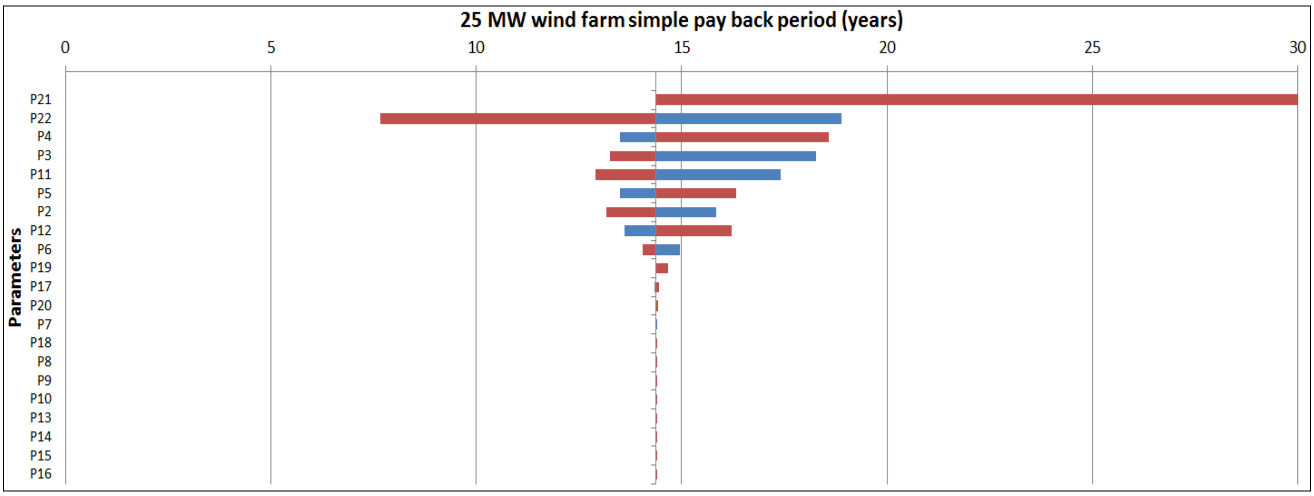


Figure 6 shows the tornado chart of the simple payback period for a system associated with a 25-MW wind farm. The "normal" value derived is approximately 14.4 years. The parameters that have the greatest impact on the overall payback period are as follows:

- P21, electricity cost;
- P22, natural gas cost;
- P4, battery feed rate;
- P3, average wind energy produced by wind farm;
- P11, electrolyser rectifier efficiency;
- P5, electrolyser full load supply duration;
- P2, maximum feed factor (to electrolyser);
- P12, electrolyser hydrogen losses from production;
- P6, battery charge range.

Figure 6. Twenty five megawatt wind farm simple payback period (years).



In the case of the electricity cost (P21), it is desirable to have a zero electricity cost. Any input electricity cost greater than approximately $0.005/kWh increases the payback period to greater than 30 years. On the other hand, it is desirable to have a higher value for the natural gas cost (P22). This is because the value of the hydrogen produced is fixed to the value of natural gas in the P2G scheme. Therefore, a higher price of natural gas increases the revenue generated from the hydrogen.

Figure 7 shows the tornado chart of the simple payback period for a system associated with a 100-MW wind farm. The "normal" value derived is approximately 13.1 years.

Figure 7. One hundred megawatt wind farm simple payback period (years).

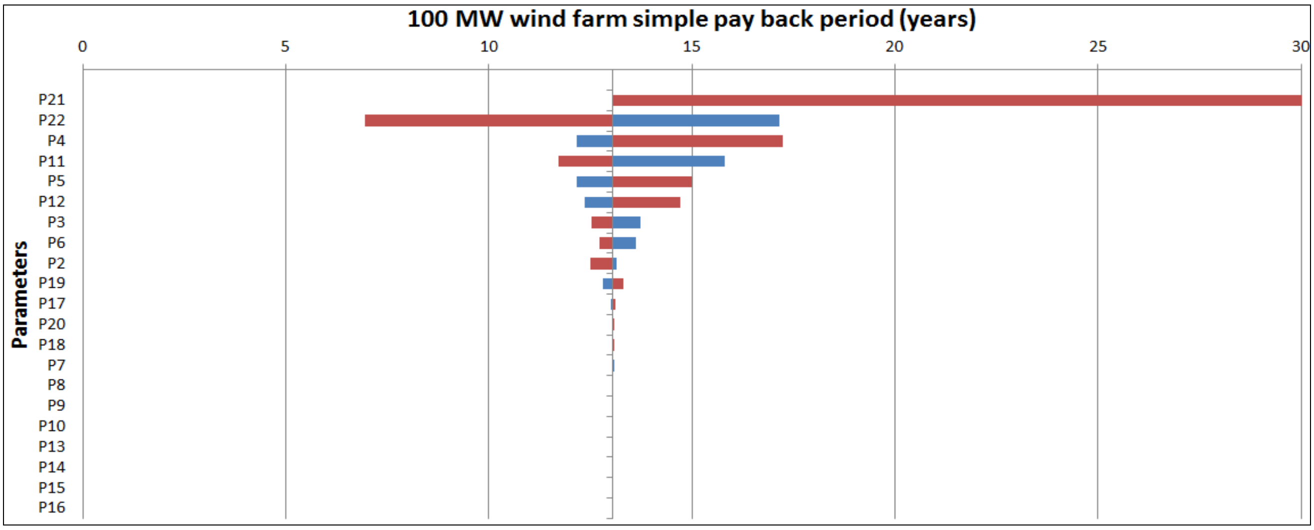
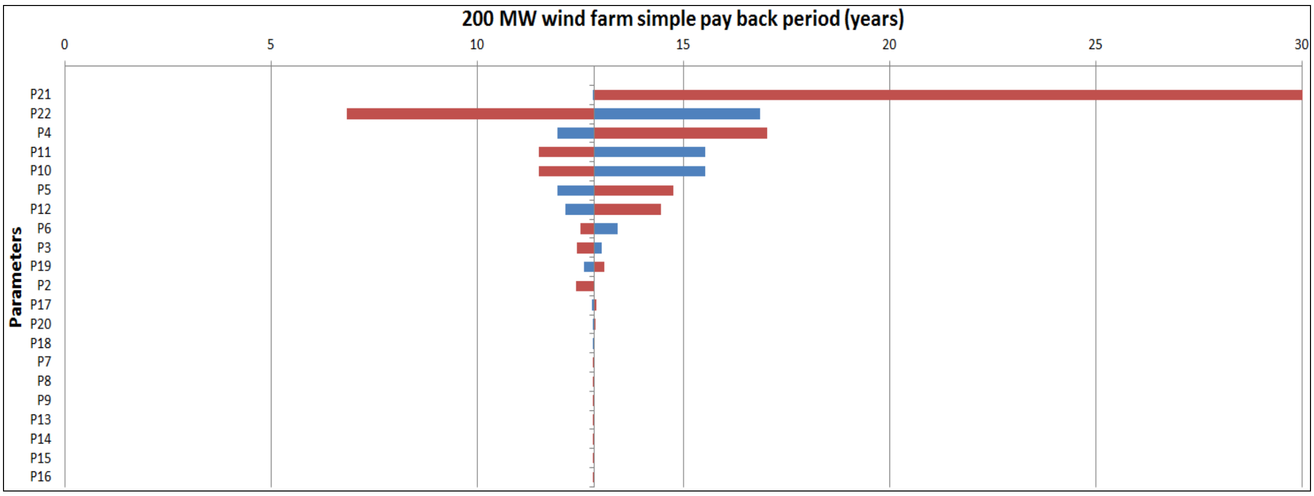


Figure 8 displays the tornado chart of the simple payback period for a system associated with a 200-MW wind farm. The "normal" value derived is approximately 12.8 years.

Figure 8. Two hundred megawatt wind farm simple payback period (years).



In addition to the previous parameters, the efficiency of the wind farm transformer becomes a more significant factor for larger wind farms. The higher efficiency means that more energy is available to the electrolyser, resulting in greater hydrogen production and increased revenue, reducing the payback period.

It is worth noting that the cost of natural gas used in the simple payback period sensitivity analysis is \$3.50/GJ [40]. If the natural gas price is more comparable to German natural gas prices (averaging nearly \$11.80/GJ over the past year) [41], then the payback periods using Equation (13) would be more acceptable: approximately four years for the 25-MW wind farm, 3.5 years for the 100-MW wind farm and 3.45 years for the 200-MW wind farm.

5. Conclusions

The benefits of utilizing hydrogen (via a P2G system) as a means to improve the economic performance of wind farms have been examined. A parametric sensitivity analysis was prepared to determine the overall capital and operating costs of the P2G system, and the simple payback period associated with each system was evaluated. Three wind farm power generating capacities were selected and analysed (25 MW, 100 MW and 200 MW), reflecting the smallest to largest wind farms currently installed in Ontario.

Based on the sensitivity analysis, the simple payback periods for the 25-MW, 100-MW and 200-MW wind farms are 14.4 years, 13.1 years and 12.8 years, respectively. Considering the large cost associated with the 200-MW wind farm and comparing the simple payback periods, the 100-MW wind farm is deemed to be the most likely choice for utilizing hydrogen in a P2G system.

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Author Contributions

Gordon Rymal Smith conceived, designed the study and co-wrote the paper. Shahryar Garmsiri collected and analyzed the data, and wrote the paper. Marc A. Rosen jointly assisted in the study, co-wrote the paper and approved the final version to be published.

Conflicts of Interest

The authors declare no conflict of interest.

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