Wind to Hydrogen in California: Case Study

O. Antonia and G. Saur

NREL is a national laboratory of the U.S. Department of Energy, Office of Energy Efficiency & Renewable Energy, operated by the Alliance for Sustainable Energy, LLC.

Technical Report
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August 2012

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Acronyms and Abbreviations

BEA	U.S. Bureau of Economic Analysis
CARB	California Air Resources Board
DOE	U.S. Department of Energy
EIA	U.S. Energy Information Administration
EPA	U.S. Environmental Protection Agency
FCEV	Fuel Cell Electric Vehicle
gge	Gallon of gasoline equivalent
GW	Gigawatt
IRR	Internal Rate of Return
ITC	Investment Tax Credit
K	Thousand
kg	Kilogram
kW	Kilowatt
kWh	Kilowatt-hour
LA	Los Angeles
LEV	Low Emission Vehicle
LRC	Lined Rock Cavern
MACRS	Modified Accelerated Cost Recovery System
MM	Million
MW	Megawatt
NREL	National Renewable Energy Laboratory
PTC	Production Tax Credit
SB 1505	California Senate Bill 1505
ZEV	Zero Emission Vehicle

Executive Summary

Fuel cell electric vehicles (FCEV) have gone through a rapid development in recent years with progress on each of the steps from research to deployment to validation [1-3]. Many believe they will be an integral element to reducing pollution and green house gasses and achieving better energy security as there is global pressure to reduce fossil fuel consumption. Production and delivery of hydrogen is vital to commercialization of FCEVs.

Currently about 95% of the hydrogen produced in the U.S. is made by steam methane reforming of natural gas. However, renewable production of hydrogen using electricity from wind, solar, or other renewable sources could be an important fuel pathway for control of regional air pollution and national greenhouse gas emissions.

As a case study we have chosen the Los Angeles (LA) area because of the California history of regulations and initiatives that target air pollution and greenhouse gas emissions and specifically seek to promote hydrogen as a transportation fuel. California regions (LA, San Francisco/Sacramento) lead the U.S. in the 2015 planned commercial deployment of FCEVs by a number of major manufacturers [4].

In 2006, the California Senate passed Bill 1505 (SB 1505) which mandates the California Air Resource Board (CARB) to set environmental standards for hydrogen production. A specific criterion of SB 1505 alongside reducing fuel carbon intensity and certain particulates is that a third of hydrogen must be produced by eligible renewable energy sources [5]. It is estimated that the zero emission vehicle (ZEV) mandate will require 50 – 100 hydrogen refueling stations by 2017 to accommodate FCEV and hydrogen bus deployments [6].

Currently wind accounts for about 3.3% of electricity generation in California and it has an installed capacity of over 3 GW with another 800 MW under construction and 18 GW in queue to be developed [7]. In the near-term, the scenario presented here might address a different approach to wind and hydrogen development which meets requirements for FCEV introduction, clean transportation fuels, as well as augmenting existing hydrogen supply.

The analysis presents a case study in California for a large-scale, standalone wind to electrolysis site. Specific geographic locations and conditions are used to present an analysis that examines localized factors. This is a techno-economic analysis of the 40,000 kg/day renewable production of hydrogen and subsequent delivery by truck to a fueling station in the Los Angeles area. This quantity of hydrogen represents about 1% vehicle market for a city such as Los Angeles (assuming 0.62 kg/day/vehicle and 0.69 vehicles/person) [8]. A wind site near the Mojave Desert was selected for its proximity to the LA area where hydrogen refueling stations are already built.

The wind profile data were selected from NREL's Western Wind Data Set [9-11]. The modified H2A FCPower Model [12-14] was used to simulate the hour-by-hour analysis of hydrogen production at a wind site. The delivery costs were calculated with the use of the modified H2A Delivery Components Model [15].

The optimized wind farm uses 61 turbines (3 MW each) with the total nameplate capacity of 183 MW. Total initial capital investments for the production plant are $354.2 MM which includes the installed costs of the wind turbines and electrolyzers. Other capital costs (which include site preparation, project contingency, engineering and design, and up-front permitting costs) are $76.7 MM. Truck terminal initial capital investments in the base case scenario (employing compression-less refueling station) are $144 MM. Refueling station capital investment for the base case scenario is comparably lower at only $191 K. We also analyzed the other delivery scenarios employing conventional trucks and refueling stations. The hydrogen delivery costs and capital investments are much higher for conventional scenarios. Delivering hydrogen in high-pressure tubes at 517 bar allows for a very simple 350 bar station design which lacks mechanical compressors and cascade storage, and has only dispenser and control and safety equipment onsite.

A standalone wind-to-hydrogen plant is both scalable and could be situated in other locations. The wind site chosen has a very high annual wind capacity of 43.2% (the ratio of energy produced yearly to the maximum possible of the wind farm). Given a comparably good wind resource, the results would be expected to be similar and there are other sites in the area of comparable wind resource. One aspect which might vary is the size of the storage, which is based upon the production and demand rate. In a standalone wind-to-hydrogen plant the production rate is tied to the variability of the wind profile. Matching the variation of the production rate over the year to the demand produces the required storage size. In this analysis we had 32 days worth of storage to meet the 40,000 kg/day demand. The hydrogen produced from a wind site near the Mohave Desert and delivered to the Burbank area is estimated to cost $9.4/kg in 2010 dollars, $5.5/kg from the production plant costs and $3.9/kg from the storage and delivery costs. A significant portion of the production cost comes from the wind turbine investment. The wind turbine sector continues to grow, and turbine costs may drop even further and benefit this system.

The cost of hydrogen given here includes 10% internal rate of return (IRR) on investment on top of the basic costs of hydrogen. The IRR encompasses a profitability which is included in the resultant cost of hydrogen. The base costs presented here do not include any kind of tax credit or other incentive for clean, renewable fuel. Finally the on road fuel economy of FCEV currently in development is around 40 – 50 miles per kg hydrogen based upon real world driving data, not sticker value, which is almost twice as high than the average gasoline vehicle [16]. Depending on the cost of gasoline in the coming years, this may make renewable hydrogen more competitive as a vehicle fuel.

There are several sensitivities that can affect that overall cost of hydrogen. On the production side two sensitivities are shown which affect the base production cost of $5.5/kg. For the base case the IRR and wind turbines have the biggest range effect for the cost of hydrogen, Figure 1. An investment tax credit (ITC) was also applied to the base case, Figure 2.

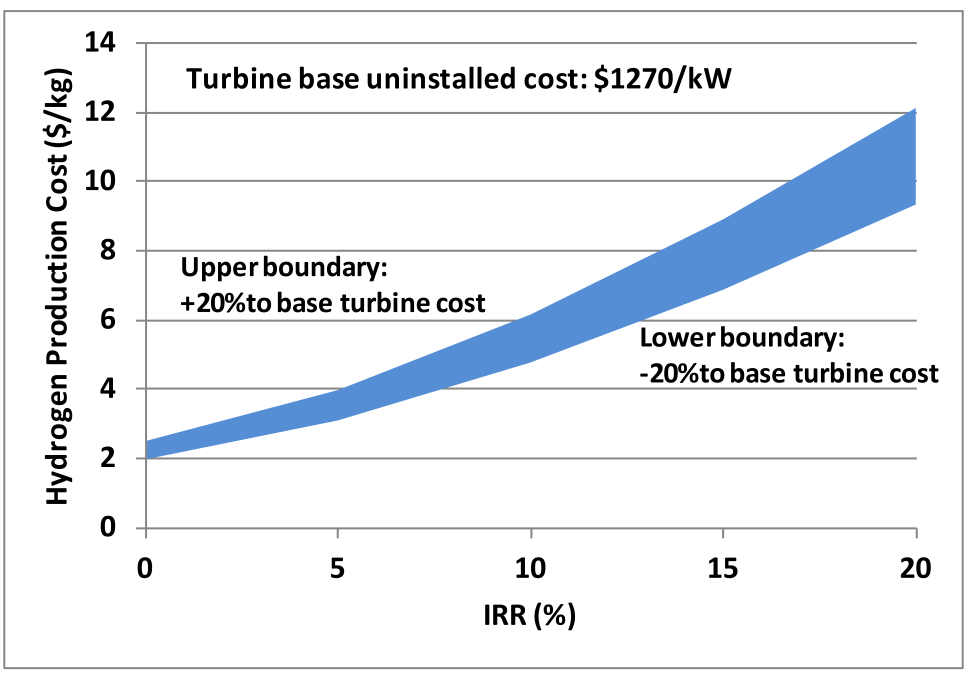

Figure 1. Range of hydrogen production cost sensitivity for increasing rate of return (IRR)

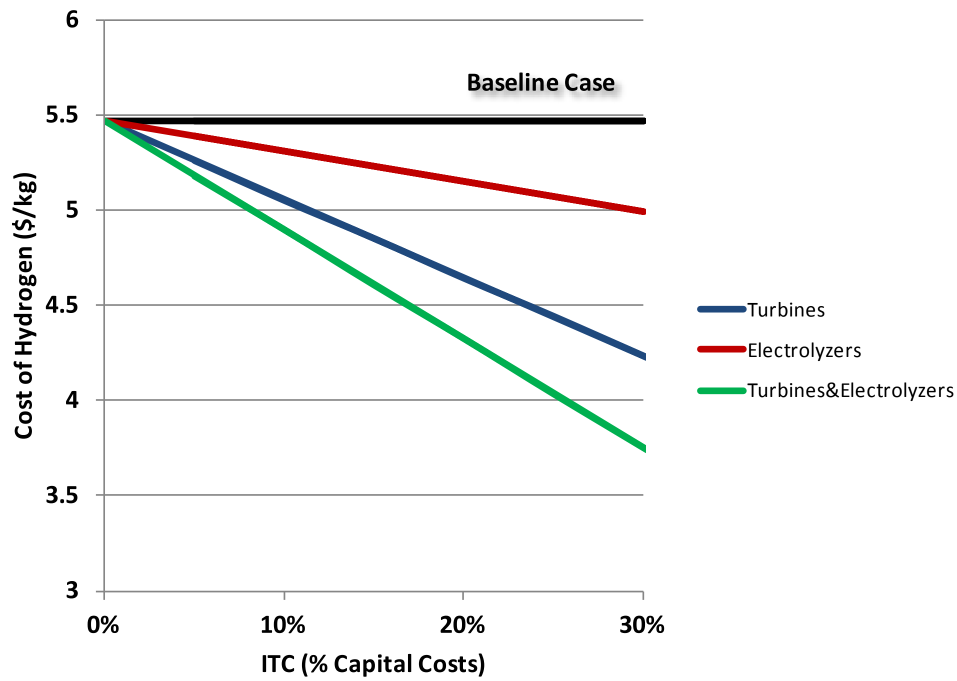

Figure 2. Hydrogen cost sensitivity to 0 – 30% ITC on select capital costs

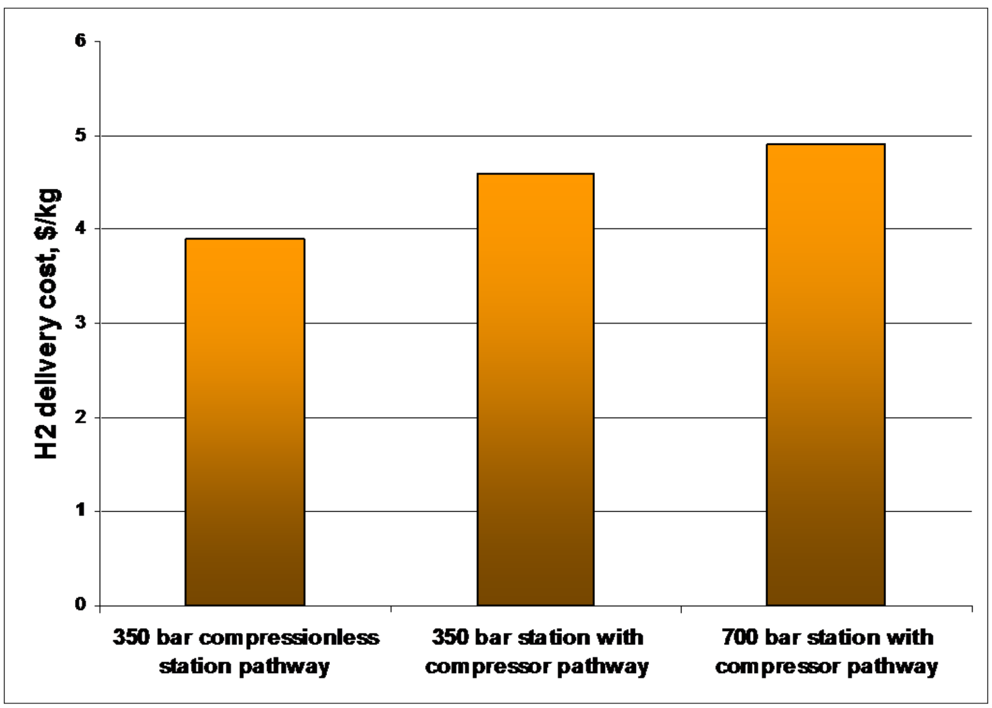

Figure 3. Dependence of the total delivery cost on type of a delivery pathway

The delivery portion of the total cost of hydrogen is sensitive to the type of refueling station. This is shown in Figure 3. The analysis base case uses a novel 350 bar compression-less station.

As demand increases, central production may become more economic. Strategic use of excavated underground cavern storage could also drive down the delivery costs. These caverns are included in the cost for storage located at the truck terminal. Wind-generated electricity cost, policy incentives, transportation improvements, and clean energy demand may also improve the conditions for renewable hydrogen production.

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1. Introduction

Fuel cell electric vehicles (FCEV) have gone through a rapid development in recent years with progress on each of the steps from research to deployment to validation [1-3]. Many believe they will be an integral element to reducing pollution and greenhouse gasses and achieving better energy security as there is global pressure on fossil fuels. Cost effective production and delivery of hydrogen is vital to commercialization of FCEVs. In the U.S., hydrogen consumption has been increasing (about 4% between 2006 and 2009), the largest consumers are petroleum refiners followed by production of ammonia and other chemicals [17]. FCEVs will only be a small part of this industry to begin with. Currently about 95% of the hydrogen produced in the U.S. is made by steam methane reforming of natural gas. However, renewable production of hydrogen using electricity from wind, solar, or other renewable sources could be an important fuel pathway for control of regional air pollution and national greenhouse gas emissions. According to the U.S. Environmental Protection Agency (EPA), between 1990 and 2009, transportation was second only to electricity generation as the largest sources of greenhouse gas emissions and nearly equal to all other sectors combined [18]. Hydrogen has the flexibility to be introduced into both of these sectors with the use of fuel cells. This makes integration of renewable electricity and cleaner transportation fuels even more attractive.

This case study is focused on the Los Angeles (LA) area because of the California history of regulations and initiatives that target air pollution, greenhouse gas emissions and specifically seek to promote hydrogen as a transportation fuel. California regions (LA, San Francisco/Sacramento) lead the U.S. in the 2015 planned commercial deployment of FCEVs by a number of major manufacturers [4]. This is only the latest step in a series of progressive environmental protection for the state of California. In 1990 California passed its first Low Emissions Vehicle (LEV) Regulation to address growing air pollution problems in the state [19]. Smog was increasing due to more pick-up trucks and SUVs being adopted as passenger cars. As a consequence California passed the first LEV regulation to impose stricter tailpipe emissions on manufacturers wishing to sell cars in the state. This was followed in 1994 by LEV II which developed a blueprint for California to achieve the federally mandated clean air goals. LEV II introduced a new compliance mechanism, the Zero Emissions Vehicle (ZEV), which includes battery electric vehicles (BEV) and FCEVs. Now in 2011 a new amendment, LEV III, is being discussed which combines several programs for compliance with smog, greenhouse gasses, and the LEV/ZEVs regulations.

Vehicle regulations alone do not address the wider infrastructure requirements for integrating these advanced vehicles. Nor are tailpipe emissions alone the sole source of emissions. The LEV regulations and amendments were supported in 2004 by executive order of Governor Schwarzenegger to create the California Hydrogen Highway in order to "support and catalyze a rapid transition to a clean, hydrogen transportation economy in California" which would 1) reduce dependence on foreign oil, 2) reduce greenhouse gas emissions, 3) improve air quality, and 4) grow the California economy [20]. These were followed in 2006 by California Senate Bill 1505 (SB 1505) which mandates the California Air Resource Board (CARB) to set environmental standards for hydrogen production. A specific criterion of SB 1505 alongside reducing fuel carbon intensity and certain particulates is that a third of hydrogen must be produced by eligible renewable energy sources [5]. It is estimated that the ZEV mandate will require 50 – 100 hydrogen refueling stations by 2017 to accommodate FCEV and hydrogen bus deployments [6].

These policies have also come with funding opportunities for advancing the hydrogen infrastructure. Over $25 MM has come from the California Hydrogen Highway Initiative which has helped CARB fund nine hydrogen stations. To date there are 26 active and in progress hydrogen refueling stations in California [21, 22]. Assembly Bill 118 includes $100 MM co-funding for dispersal by the California Energy Commission to promote alternative fuels [6]. Between ZEV mandates and hydrogen fuel regulations, California is a ripe environment for examining renewable hydrogen to meet the evolving regulations and transportation landscape.

Utility scale wind energy facilities are one approach to renewable electrolysis. Wind power is a quickly growing resource in the U.S. and globally. California had the first utility-scale wind projects in the U.S. and until 2000, when it was eclipsed by Texas and Iowa, had been the largest producer of wind electricity. Currently wind accounts for about 3.3% of electricity generation in California and it has an installed capacity of over 3 GW with another 800 MW under construction and 18 GW in queue to be developed [7]. Increasing penetration of variable renewable electricity has not been without problems. Texas, which leads the nation in wind power capacity with over 10 GW installed, generates about 6.4% of its electricity from wind [23]. Texas utilities have experienced two severe ramping events in recent years where wind production in a large geographic area changed drastically over a short time taxing the available utility infrastructure [24]. Ramping events are one among other issues of integrating larger penetrations of variable renewable energy [25]. Larger use of energy storage, of which hydrogen is one possibility, may aid the continued development of these resources. However, in the near-term, the scenario presented here might provide a different approach to wind and hydrogen development which meets requirements for FCEV introduction, clean transportation fuels, as well as augmenting existing hydrogen demand.

The analysis presents a case study in California for a large scale, standalone wind electrolysis site which takes into account local factors. This is a techno-economic analysis of the renewable production of hydrogen via electrolysis and subsequent delivery to a fueling station. A wind farm near the Mojave Desert was selected due to its proximity to the LA area where hydrogen refueling stations are already built. This location could be supplemented for both supply and demand by a petroleum refinery operation in Bakersfield. The emphasis for the analysis is on hydrogen as a renewable vehicle fuel. However, near term development of these systems should not ignore other economic outlets while the demand for alternative vehicle fuel ramps up. The California regulations for renewable hydrogen may help spur demand for such a system as well as give wind developers other revenue avenues to pursue. This detailed case study takes into account real locations and conditions to help provide context for the example.

2. Scenario

The scenario we analyze includes hydrogen production using wind-generated electricity and water electrolysis and then delivery to a hydrogen refueling station (Figure 4). The scope of this case study is not to evaluate the entire infrastructure cost, but to estimate the hydrogen dispensed cost for a particular production and delivery pathway.

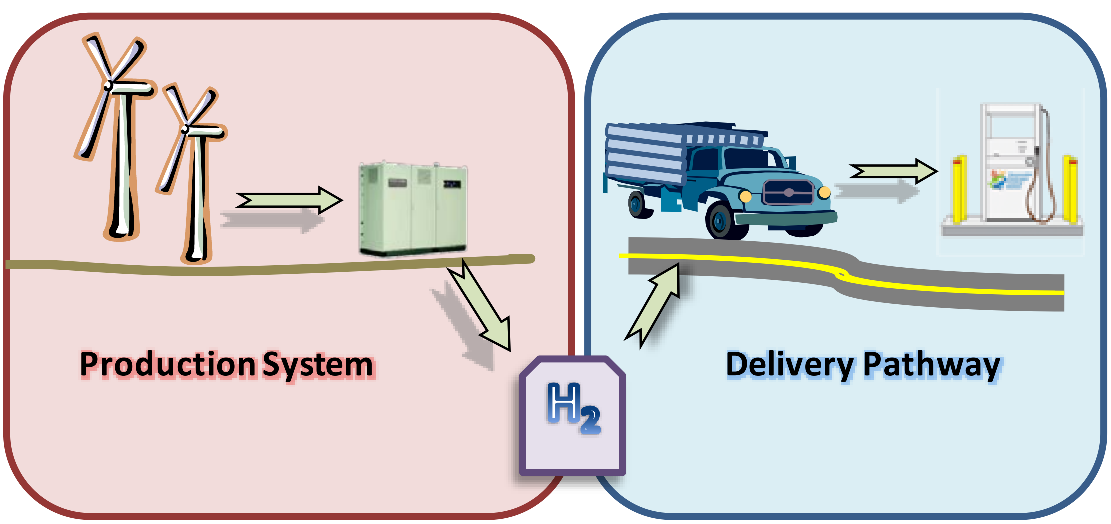

Figure 4. Renewable hydrogen pathway

For our scenario, we have chosen the location for the wind farm near Mojave Desert, CA, at the foothills of Middle Knob Mountain, and approximately 6 miles from Mojave, CA (see Figure 5). This location is convenient due to its proximity to the Los Angeles area (about 100 miles) and to Bakersfield, CA (about 50 miles). Proximity to the Bakersfield area is convenient in terms of sustainability of the hydrogen supply. There are several oil refineries in Bakersfield. Hydrogen is used to process crude oil into refined fuels, such as gasoline and diesel, and for removing contaminants, such as sulfur, from these fuels. Hydrogen demands in the petroleum industry have increased recently for a variety of reasons including more heavy, high sulfur crude runs, more stringent limits for sulfur in highway diesel, and demands for hydrogenate benzene for reformulated gasoline specifications [17, 26]. Approximately 75% of hydrogen currently consumed worldwide by oil refineries is supplied by large hydrogen plants that generate hydrogen from natural gas or other hydrocarbon fuels, with the balance being recovered from hydrogen-containing streams generated in the refinery process [27]. Potentially, fluctuations in hydrogen demand that are not covered by the wind farm could be supported by buying hydrogen from refinery hydrogen plants. In order to reduce their carbon footprint the refineries could be another potential demand for hydrogen from the wind-to-hydrogen facility.

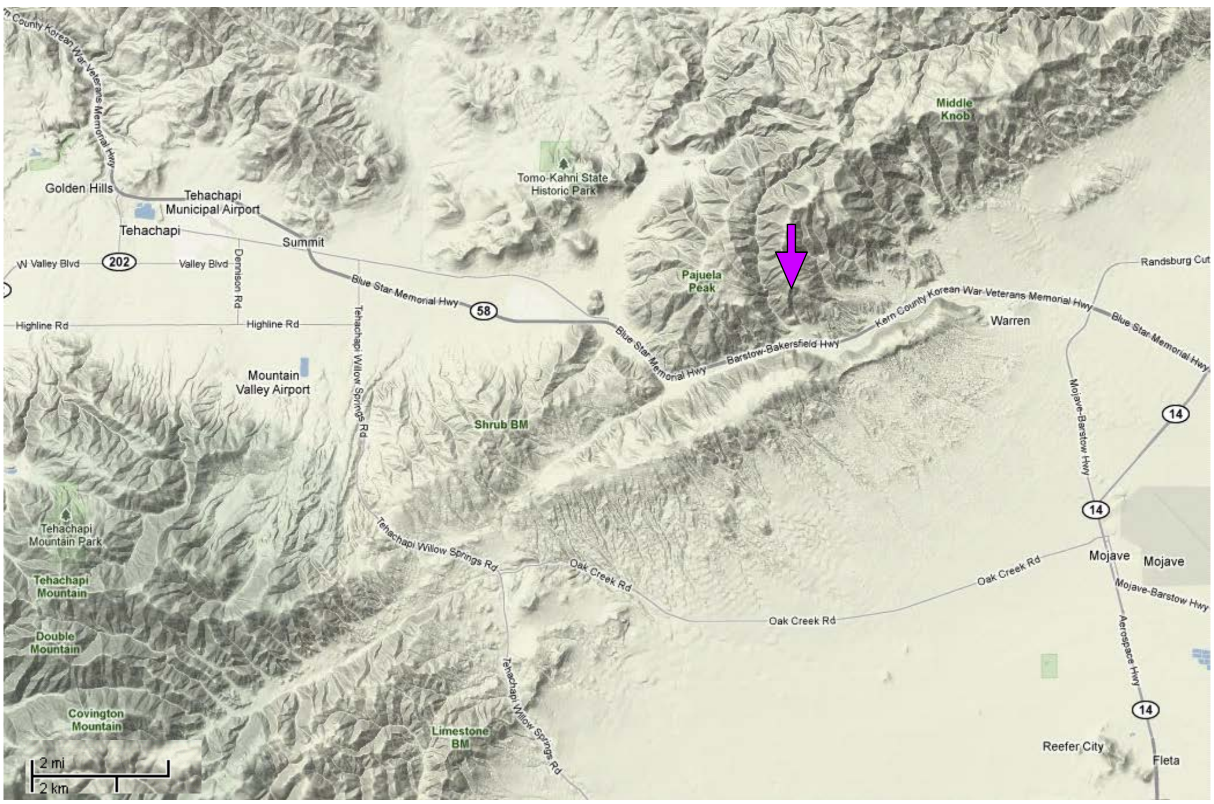

Figure 5. Assumed wind farm near Mohave Desert close to CA Route 58

Water resources are a significant issue within many areas of California. Water electrolysis uses process water for the production of hydrogen. It may also require cooling water depending on the cooling method employed. A popular method of cooling on this scale is once-through cooling which uses a significant amount of water. However, there are options for closed-loop cooling which decrease the cooling water usage to nearly zero with minimal effect on the overall cost of hydrogen. The cooling method employed will depend greatly on the geographic location chosen. For comparison to this case study we can look at the recent approval of the Beacon Solar Energy Project which is a 250 MW solar thermal electricity project which uses steam generators. This project lies about 15 miles north of Mojave, CA in the same general region as our scenario location. The CEC final decision report lists the area as having extremely limited water resources [28]. The estimated operational water usage by this plant would more than cover the approximate process water consumed by electrolysis. Further examination of water in the area and several methods of cooling are evaluated. In general these issues would impact site placements for this kind of hydrogen generation system.

There already exist several large-scale wind farm projects in the Mojave Desert, including the nation's biggest wind power plant with the projected generating capacity of three nuclear power plants [29]. All the considerations led to the choice of this location as the site for our scenario.

In our near-term scenarios, we assume a standalone wind farm **without** electricity grid connection capable of producing 40,000 kg/day of hydrogen via wind electrolysis with excavated underground cavern storage onsite sized for 32 days of storage. This quantity of hydrogen represents about 1% of the vehicles for a city such as Los-Angeles (assuming 0.62 kg/day/vehicle and 0.69 vehicles/person) [8]. The production capacity would supply approximately 40 hydrogen refueling stations designed for 1,000 kg/day. Hydrogen at the terminal is pumped into tubes and delivered by truck to the refueling stations. Each truck carries 930 kg hydrogen per delivery. The refueling station uses a novel 350 bar compression-less design for dispensing. For simplicity sake, we assume uniform refueling station distribution and approximate delivery distance of 100 miles.

A potential delivery route is shown on Figure 6. It is an example route that we used in the case study for a distance reference. The impact of changing traffic patterns due to hydrogen delivery trucks is not within the scope of this study.

Figure 6. Hydrogen delivery route from the wind farm to the refueling station in Burbank, CA.

3. Model and Data Description

In this analysis we have used a modified version of the H2A FCPower Model 1.2 and a modified H2A Delivery Components Model to develop the techno-economic analysis of the scenario [13-15]. The models use capital and operating cost estimates from industry to approximate the cost of different components in the pathway. The production plant and size of storage were optimized within the H2A FCPower Model's hourly analysis output. The storage cost and delivery pathway were evaluated in the H2A Delivery Components model. The process flow diagram of the system is shown in Figure 7.

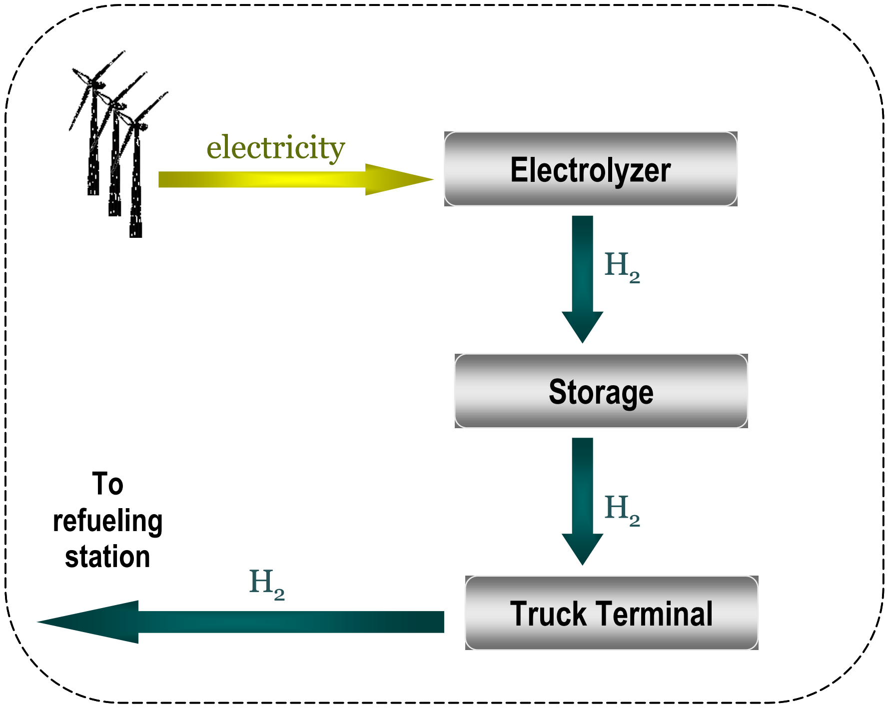

Figure 7. Process flow diagram

3.1. Economic Assumptions

We assume that the project started up in 2010 with 2 years of construction period and 100% equity financing. Table 1 shows the list of economic parameters used in the scenario.

For all equipment, a MACRS depreciation schedule was used. The depreciation schedule can be seen in Table 2. The replacement schedule is shown in Table 3 which includes periodic replacement of worn parts. For this analysis the electrolyzer cells are replaced every 7 years with 25% of the initial uninstalled capital cost [30] and yearly maintenance is $8,256 per electrolyzer. The wind turbines are overhauled every 20 years with 20% of the initial installed capital cost (Table 3) and yearly maintenance of $6,600 per turbine. The replacement costs for the terminal, truck and refueling station dispensers are calculated within the H2A Delivery Components Model using the following equation [15].

$$Replacement\ Cost = \left(\frac{1 + Inflation\ Rate}{1 + IRR}\right)^{Lifetime(years)} * Installed\ Capital\ Cost$$

Equation 1

All costs are escalated to 2010 dollars using Bureau of Economic Analysis' Price Indexes for Gross Domestic Product [31].

Table 1. Financial parameters used in the scenario

Select Financial Parameters	Value
Assumed Startup Year	2010
Length of Construction (years)	2
Plant Life (year)	40
Equity financing (%)	100
Debt Financing (%)	0
Production Plant Analysis Period (years)	40
Terminal and Refueling Station Analysis Period (years)	20
Inflation Rate (%)	1.9
After-tax real internal rate of return (IRR) (%)	10
State Taxes (%)	6
Federal Taxes (%)	35
Total Tax Rate (%)	38.9

Table 2. MACRS depreciation schedule

Equipment	Depreciation Schedule (years)
Wind Turbines	5
Electrolyzers	7
Terminal Equipment	20
Truck Cab and Trailer	5
Refueling Station Dispenser	7

Table 3. Equipment replacement summary

Equipment	Replacement Period (years)	Replacement Cost
Wind Turbines	20	20% initial installed capital cost
Electrolyzer	7	25% initial uninstalled capital cost
Terminal Equipment	20	evaluated by Equation 1
Truck Cab	5	evaluated by Equation 1
Truck Trailer	20	evaluated by Equation 1
Dispenser	10	evaluated by Equation 1

3.2. Wind Data

The wind profile data were selected from NREL's Western Wind Data Set [9-11]. These sites underwent several steps of evaluation for inclusion in the dataset by NREL Wind Technology Center researchers. The sites were screened to remove recreational and other non-developable areas. Suitable or promising wind sites were further narrowed through an iterative selection algorithm. This dataset was created using numerical weather prediction models to recreate historical data from 2004-2006 for sites spanning U.S. The wind speeds were developed with temporal intervals of 10 minutes and spatial samples of an arc-minute (~2 km). The dataset has yearly wind speed and power data for each site in 10 minute intervals. The power output was modeled as Vestas V90 3 MW turbines and further corrected using validation models from 3TIER [9-11].

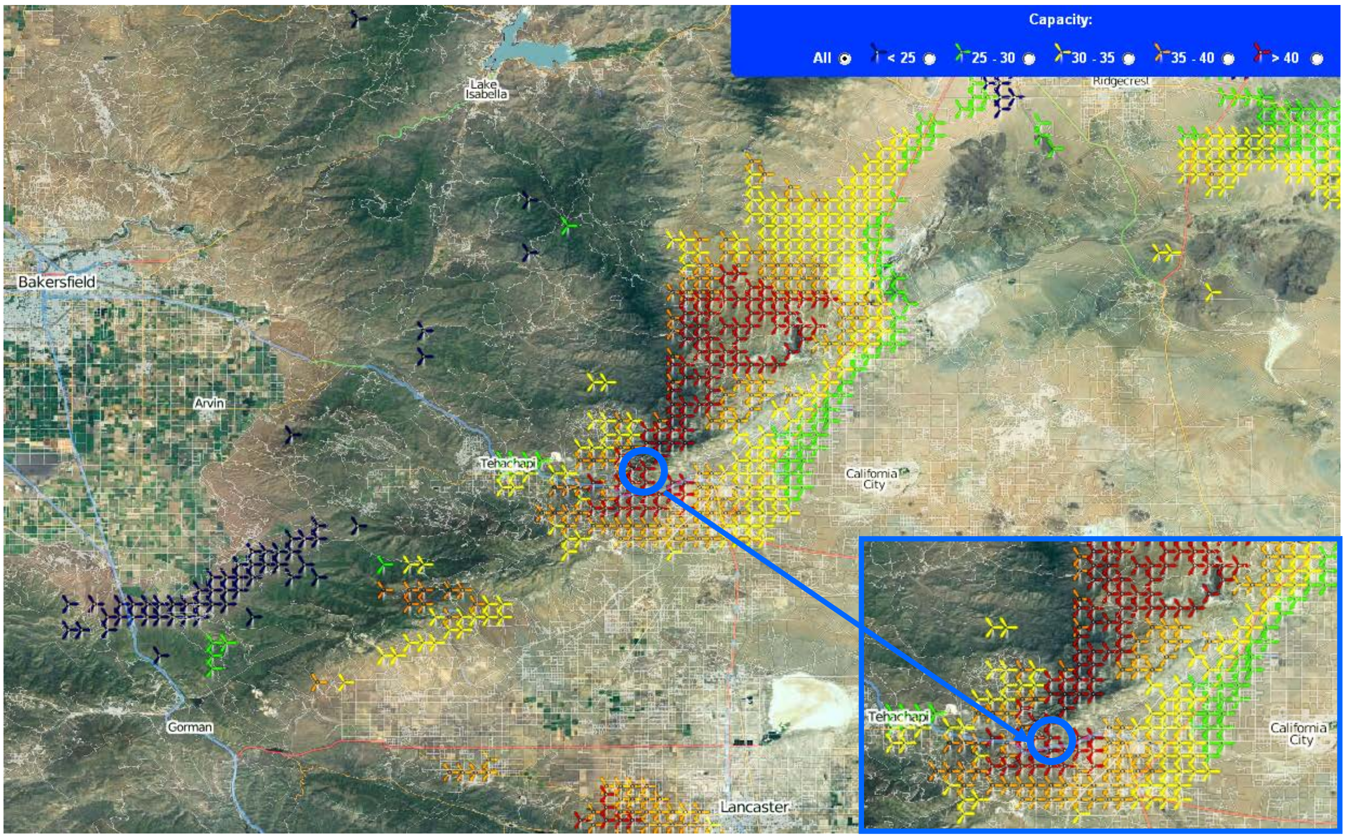

Figure 8. Wind sites in NREL's Western Wind Dataset near Mohave Desert area [9]

This analysis uses the 2006 dataset for a wind site near the Mohave Desert, location of 35.13N 118.27W and elevation 1346 m, see Figure 8 and inset. This site has an average wind speed at 100 m of 9.2 m/s and a power density of 818.8 W/m^2. The annual capacity factor of the wind site is 43.2%. The capacity factor is the ratio of energy produced yearly to the maximum possible of the wind farm. It can also be seen in Figure 8 that there are a number of good wind sites nearby; sites with red turbine icons are those with greater than 40% capacity factors while orange are between 35-40% capacity factor and other colored turbine icons can be seen in the legend. The original data were modeled off of 30 MW wind farms (ten 3 MW turbines) which was adjusted in this analysis to accommodate the actual size of the wind farm needed in our scenario, 183 MW. However, the hourly wind profile provides the variation of wind power production over the year. An hourly profile was created by averaging each hour of 10 minute data over the 8,760 hours per year. The wind power production profile we used can be seen in Figure 9.

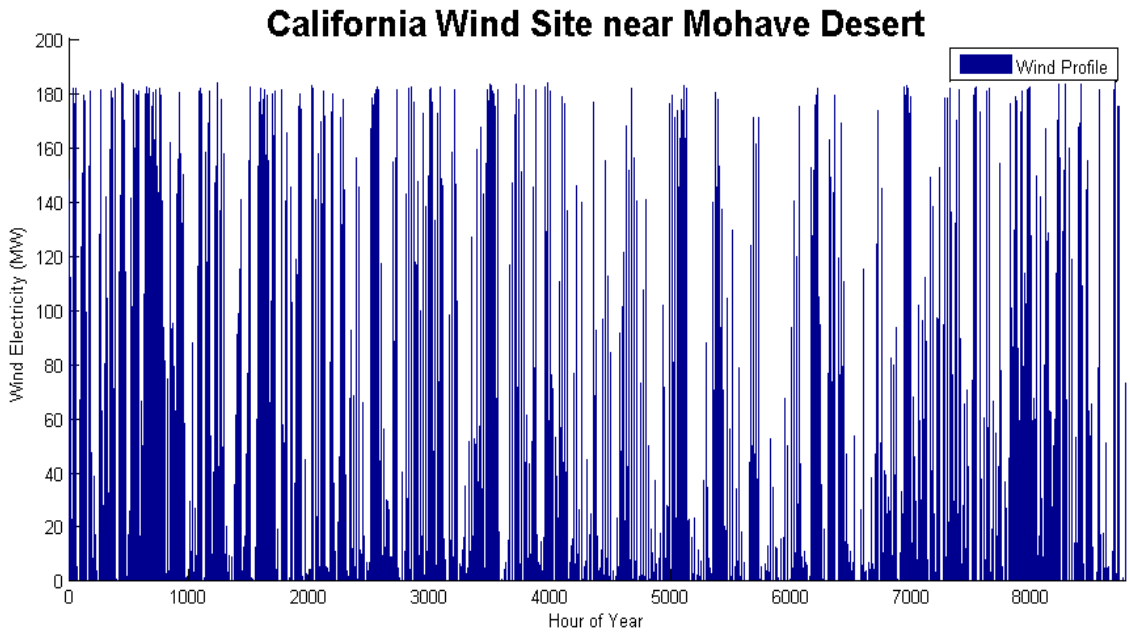

Figure 9. Hourly wind profile of site near Mohave Desert

3.3. Wind Turbine Cost

Several sources for wind costs were considered for this analysis including the 2008 Wind Technologies Market Report, the 2010 Wind Technologies Market Report, and a Bloomberg New Energy Press Release on 2011 costs of turbines [32-34]. The range of capital costs can be seen in Table 4.

Table 4. Recent of wind turbine costs

Source	Project Year	Installed Project Cost ($/kW)
2008 Wind Technologies Market Report (2008$)	2008	1,915
2010 Wind Technologies Market Report (2010$)	2010	2,155
Bloomberg PR 07 Feb 2011 (2011$)	2011 (U.S.)	1,270

While wind costs since 2004 have on average been slowly increasing, there are indications that they are leveling off and now falling [33] at least temporarily. Increased scale of projects, better new turbine efficiencies, and manufacturing over-stock due to the global economic downturn have driven recent wind development project costs down as seen in the Bloomberg press release [34]. In looking at the near term project feasibility we decided to use the Bloomberg costs for our analysis.

Bloomberg New Energy Finance analyzed confidential data provided by 28 major purchasers of wind turbines. The sample includes more than 150 undisclosed turbine contracts, totaling nearly 7 GW of capacity in 28 markets globally – with a main focus on Europe and the Americas. Global turbine contracts signed in late 2010 for delivery in 2011 display very aggressive pricing, with average values at $1,330/kW). This is a 7% decrease compared to contracts signed in 2009 ($1.44 MM/MW) and 19% down from peak values in 2007-08 ($1.65 MM/MW). The US exhibited the lowest pricing of all markets so far with values averaging $1,270/kW.

An installation factor of 1.1 is applied to the uninstalled capital cost to arrive at the installed capital costs of the turbine.

3.4. Electrolyzer

The electrolyzer was modeled using basic performance and cost data from a DOE-sponsored independent review panel report on low-temperature electrolyzers with an alternative to the once-through cooling system assumed in the report [30]. The once-through cooling system was replaced by a closed loop system using a vendor database of installed costs for various systems [35]. A large-scale plant such as modeled here would require multiple units. Current state-of-the-art stack sizes are limited to approximately 1500 kW units [30]. The units are assumed to be skid-mounted alkaline electrolyzers for easy installation. The electrolyzers have a conversion performance of 50 kWh/kg at rated power. The electrolyzer is sized equal to the wind turbines at 183 MW in order to use all available wind capacity. Stack replacements are 25% of the initial capital investment every 7 years and yearly maintenance of $8,256 per electrolyzer. Electrolyzer installed cost is $537.6/kW [30]. Electricity rate used is $0.1/kWh. The cooling requirement for the electrolyzers are approximately 61 MW [30]; however, water consumed for cooling is assumed to be zero for a closed loop cooling system in which the water recirculates.

Despite the limited water resources of the area, as seen in the CEC assessment of the Beacon Solar Energy Project site, the operational estimates of water required for that project would cover the electrolysis process water needs of about 2.5 gal/kg H_2. The Beacon Solar Energy Project estimates an annual requirement of 452 MM gal (1,388 acre-feet) of potable and other water consumed [28]. By comparison the electrolysis annual process water needs would be approximately 36.6 MM gal of de-ionized water. However, a once-through cooling system would have required approximately 4,242 MM gal annually. Given the water limited resources of the area, an air-cooled closed-loop system in which water is not consumed only re-circulated is assumed. The resulting difference in the cost of hydrogen between a once-through cooling system and an air-cooled closed loop system was about $0.03/kg which easily falls into the margin of error.

3.5. Storage

Given a variable nature of wind profiles in general, wind farms for sustainable hydrogen production and delivery usually need a large hydrogen storage of a month of demand or larger. Geologic storage is one of the most economic options for such volumes of hydrogen. Currently, the geologic formations used for hydrogen storage are salt domes [28]. However, there are only two existing hydrogen salt caverns in the U.S. owned by ConocoPhillips and Praxair. Both storage sites are located within the Clemens salt dome in Texas [36]. The potential locations of salt caverns are rather sparse throughout the U.S. (Figure 10) [37].

The other candidates of geologic storage for hydrogen are depleted gas/oil reservoirs (Figure 11) and aquifers (Figure 12) [36]. Aquifers and depleted reservoirs possess the largest capacity and require the greatest volume of cushion gas [36]. The reservoirs are typically cycled once annually and are used to meet base load demand. However, aquifers must be proven to trap and contain gas. Salt caverns are solution mined and hold a fraction of the gas volume than that of depleted reservoirs and aquifers [36]. Additional research is required regarding geologic storage for hydrogen to ensure hydrogen containment and purity. The important topics in this research are: hydrogen mobility, hydrogen embrittlement, potential gas mixing, and effect of hydrogen on rock properties [36].

Another technology that has been explored is excavated lined hard rock caverns [38, 39]. The lining (usually plastics or steel) completely contain the gas. Lined caverns also operate at much higher pressures than unlined caverns. As with salt caverns, lined hard rock caverns can be withdrawn over multiple cycles and can deliver gas at high rates [39].

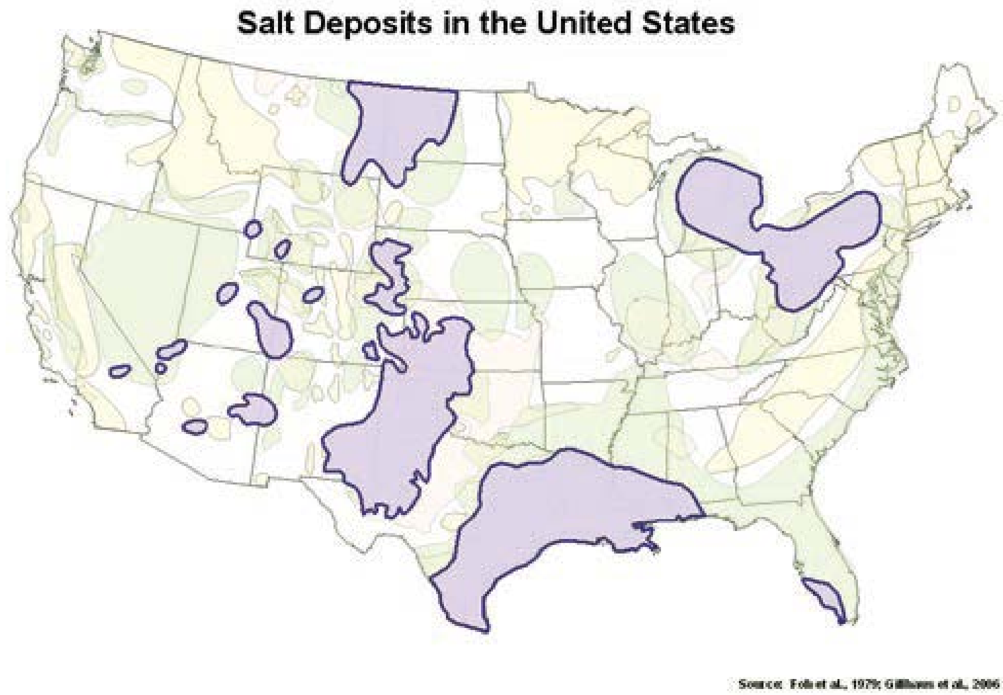

Figure 10. Salt deposit storage potential in the U.S. Source: Sandia National Laboratory [37].

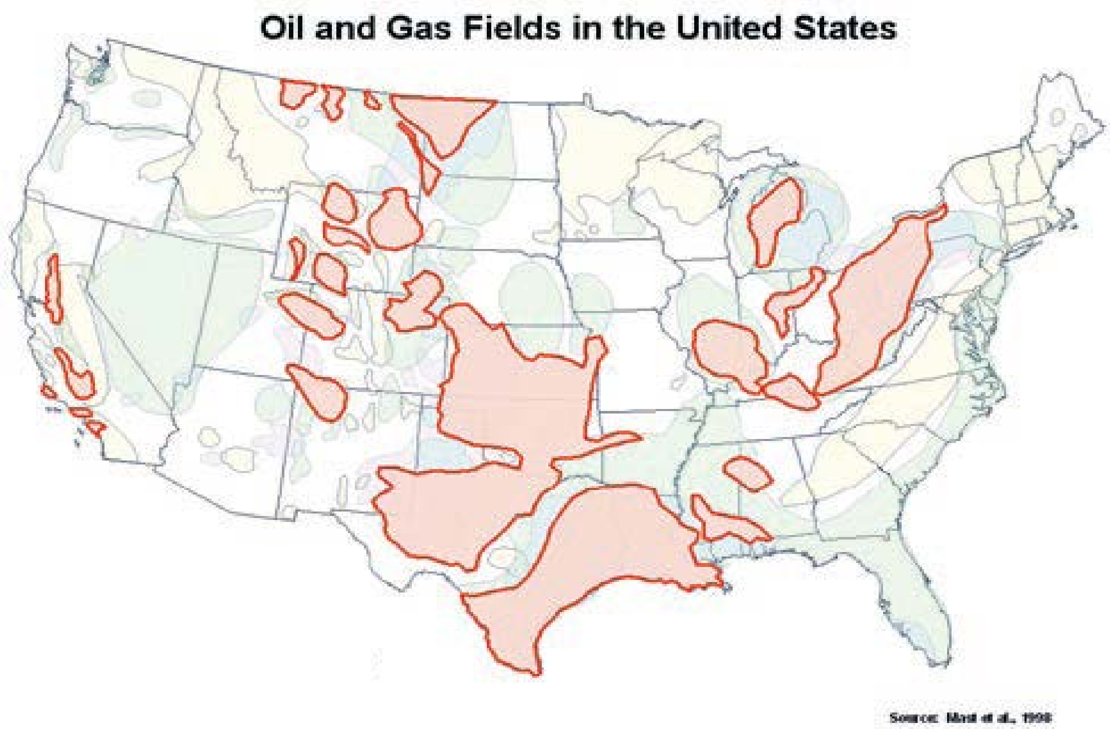

Figure 11. Depleted oil and gas storage potential in the U.S. Source: Sandia National Laboratory [37].

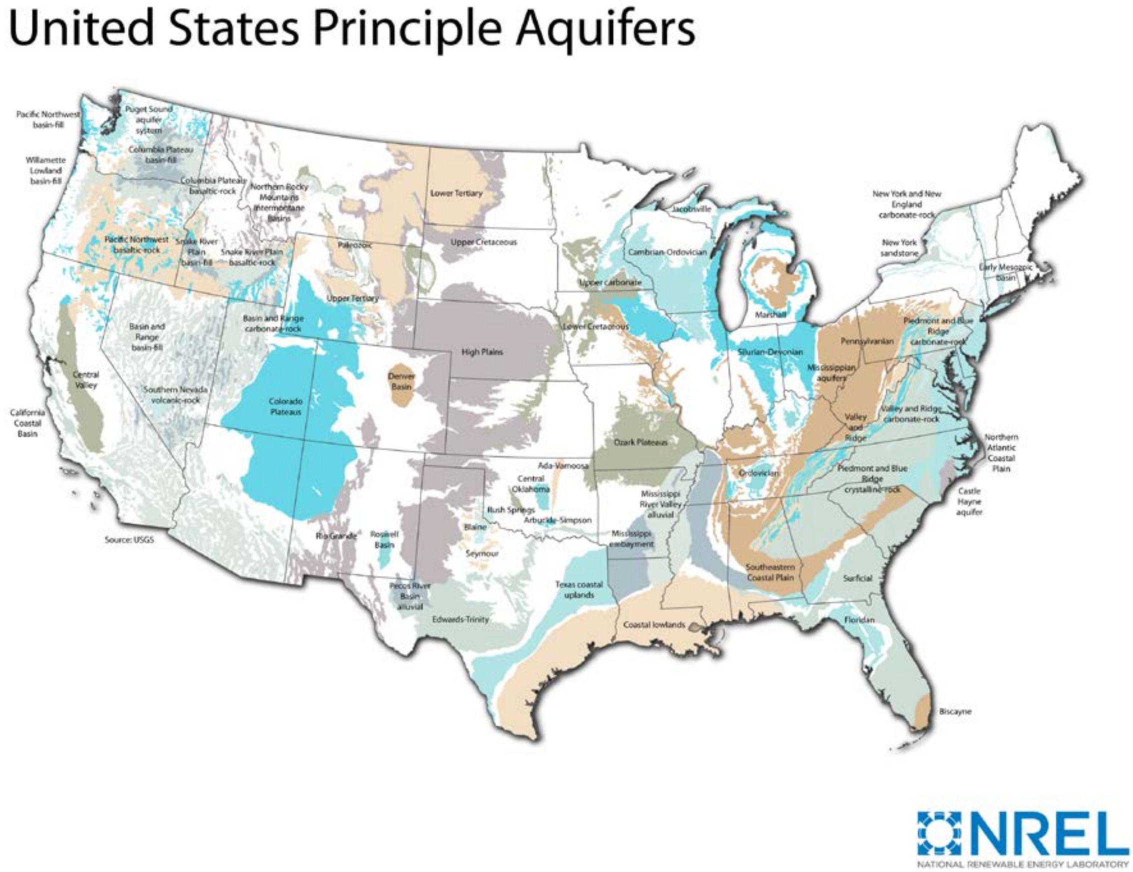

Figure 12. Aquifers as a potential hydrogen storage in the U.S. NREL GIS Team [40]. Source: U.S. Geological Survey [41]. Various colors designate different aquatic basins.

3.6. Delivery Pathways

We considered three delivery scenarios: 700 bar and 350 bar conventional hydrogen refueling stations, and a 350 bar compression-less station pathway, the third scenario being a base case.

In all three delivery scenarios, hydrogen is delivered by truck from the wind farm to the Los Angeles refueling stations over the distance about 105 miles. Hydrogen from the wind farm goes to bulk excavated cavern storage sized to approximately 32 days of demand located at the truck terminal. From bulk storage the hydrogen is pumped into transportable tubes to a pressure of 517 bar. The tubes are the part of a tube-trailer which can transport 930 kg of hydrogen onboard by truck.

The recent developments in tube technology allow for consideration of hydrogen delivery scenarios which use compression-less refueling stations. Such stations would draw hydrogen directly from the tube trailer, therefore not requiring expensive auxiliary compressors and cascade storage system. A portion of the hydrogen in such a system will be left in the tubes unused due to very low pressures at the end of the refueling strategy. A model was developed to calculate the portion of unused hydrogen as dependent on the number of tubes per truck used. The model estimation converges on 90% useable hydrogen (10% unusable) per truck using the tubes themselves as a cascade refueling system (see Figure 13). Being guided by these results in the absence of real world data regarding such configuration, we have chosen to use 80-90% trailer usability for our analysis.

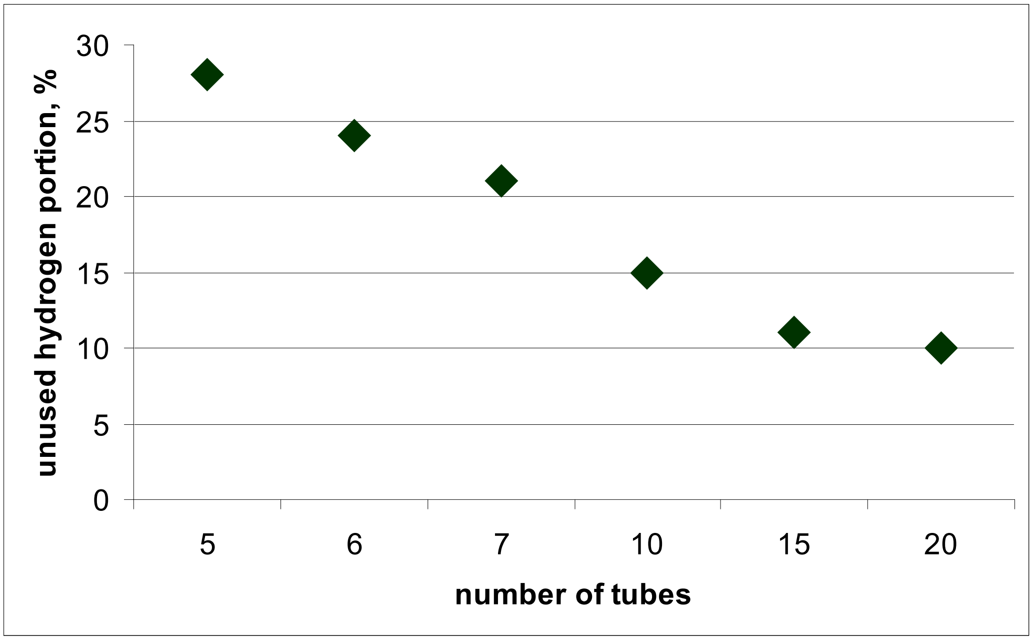

Figure 13. Estimated portion of unused hydrogen per truck (computer simulation results).

In the base case delivery scenario, employing 350 bar compression-less refueling station with a capacity of 1000 kg/day, hydrogen is dispensed from tube-trailer directly into vehicles. The production plant would be capable of supplying 40 such stations in the Los Angeles area. The delivery cost presented here is the dispensed hydrogen cost from production plant gate to vehicle.

We modified the H2A Delivery Components Model [15] to calculate hydrogen storage and delivery cost for the above scenario. For this model, we used the techno-economical data for the existing underground storage facility located at Skallen near Halmstad in southern Sweden [39]. The Skallen project which uses Line Rock Cavern (LRC) technology was launched in 1998 and became operational in 2004. Currently, the cavern operates commercially at 2900 psi as part of the Swedish gas grid [42]. Lined cavern development implies an excavation into an igneous or metamorphic rock, applying a layer of concrete to withstand and absorb the pressure load, and an adhering, impermeable, chemically resistant lining. Liners can be made of steel or polypropylene plastic.

The storage size was calculated during wind farm optimization based on daily demand, wind profile, as well as on electrolyzer and turbine sizes. The optimized size of storage is 32 days. The terminal also has buffer storage for of 0.25 days of the daily demand. Buffer storage uses steel tubes with 88.9 kg of hydrogen capacity.

The terminal uses three truck loading compressors with two of them working any time and one compressor as a backup. Trailer truck capital cost was assumed to be $866/kg of hydrogen.

Electricity is needed to run the terminal compressors and the refueling station dispensers. These electricity rates are taken from the U.S. Energy Information Administration (EIA) [38] based on sales of California electric companies. We used an industrial rate of 0.10 $/kWh for the terminal, and a commercial rate of $0.12/kWh for the refueling station.

4. Results

The total cost of hydrogen produced from the electricity at the wind farm and delivered to and dispensed at the Los Angeles area refueling stations is \$9.4/kg. Production cost is \$5.5/kg, and storage and delivery cost is \$3.9/kg. The details of the costs are given below.

While these analysis results are the product of a specific wind site and destination, the standalone site is scalable and it is expected that similar good wind sites would produce similar production results for cost of hydrogen. As can be seen in Figure 8 there are other suitable wind sites with similar capacity factors in the area chosen. Delivery costs are dependent on distance to the demand site; however, one big factor in the cost is the size of storage required. This storage cavern size is a consequence of the individual wind profile, size of wind turbines and electrolyzers, and the hydrogen demand, i.e. production rate over the year and demand rate. In our particular scenario with wind turbines and electrolyzers rated at 183 MW and a 40,000 kg/day demand the cavern size was about 32 days of the demand. This was enough to capture hydrogen during higher production times to meet demand during lower production times over the course of the year, essentially meeting a flat seasonal demand with a variable production rate. This particular element of the analysis would vary based upon the production and demand rates assumed and would have a significant effect on the delivery costs as will be discussed below.

4.1. Production Cost

The optimized production plant shows the levelized cost of hydrogen production under 10% IRR at \$5.5/kg.

The optimized wind farm uses 61 turbines (3 MW each) with the total nameplate capacity of 183 MW with the uninstalled turbine cost of \$1270/kW [34] and the installations factor of 1.1. An optimized production plant uses electrolyzers with the total nameplate capacity of 183 MW, same as the wind turbines in order to capture all available wind electricity, with the initial installed capital cost of \$533/kW [30].

Total installed capital investment for production plant is \$354.2 MM which includes the installed costs of the wind turbines and electrolyzers. Other capital costs (site preparation, project contingency, engineering and design, and up-front permitting costs) are \$76.7 MM. Total annual operating costs are \$15.6 MM. Fixed operating costs include plant staff labor, overhead, licensing and permitting fees, property tax, insurance, material costs (mainly electrolyte for the electrolyzers), and maintenance and repair costs. Property tax and insurance account for more than two thirds of the fixed operating costs of the production plant. The variable operating costs consist of electricity feedstock costs to run the compressors and material costs for the electrolyzers, mainly de-ionized process water, cooling water, and inert gasses for purging gas lines of combustible gas.

Table 5 shows the major production plant capital and annual operating costs. A breakdown of the installed capital investments is seen in Figure 14 where wind turbines account for 72% of the total while electrolyzers are less at only 28%. Other capital cost breakdown is shown in Figure 15.

Table 5. Major Capital and Operating Costs for Production Plant

Wind Farm	
Nameplate Capacity (MW)	183
Uninstalled Capital Cost($/kW)	1270
Installed Capital Investment ($ MM)	256.3
Electrolyzers	
Nameplate Capacity (MW)	183
Installed Capital Cost ($/kW)	533
Installed Capital Investment ($ MM)	97.8
Total Production Plant Costs	
Total Installed Capital Investment ($ MM)	354.2
Other Capital Costs ($ MM)	76.7
Total Initial Capital Investment ($MM)	430.8
Total Fixed Operating Cost ($ MM)	*15.5*
Total Variable Operating Cost ($ MM)	*0.07*
Total Operating Costs ($ MM)	15.6

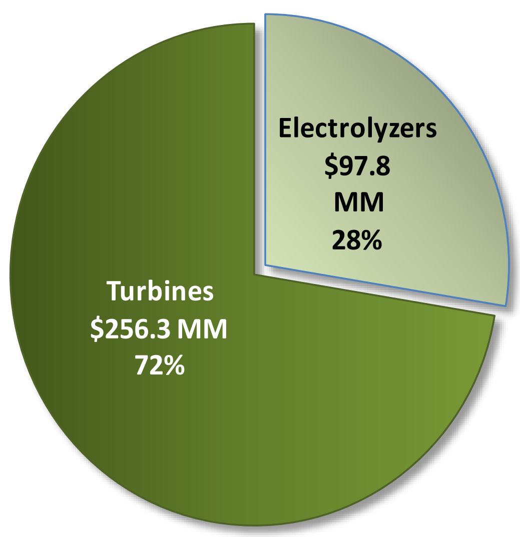

Figure 14. Breakdown of installed capital investment for production plant ($354.2 MM)

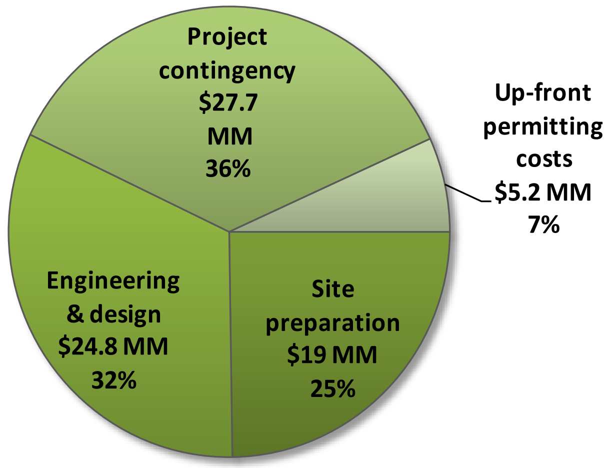

Figure 15. Breakdown of other capital costs for production plant ($76.7 MM).

Figure 16 shows the production cost sensitivity to internal rate of return (IRR), wind turbine and electrolyzer costs. IRR is the most sensitive parameter to the levelized hydrogen production cost. Decreasing IRR to 5% drops production cost to $3.5/kg while 15% IRR increases production cost to $7.9/kg. Varying base turbine cost of $1270/kW by 20% results in a range from $4.8/kg to $6.2/kg from the base case levelized production cost of $5.5/kg. Varying the installed electrolyzer costs by 20% showed less sensitivity than the IRR or turbine cost all of which can be seen in Figure 16. This sensitivity impact follows from the percentage wind turbines and electrolyzers had in the initial capital investment seen in Figure 14.

The effect of IRR can be seen in Figure 17 which shows a range of hydrogen production cost under varying IRR from about zero to 20%. The range band is bounded by the wind turbine base cost sensitivity of ± 20%. Sensitivity to the electrolyzer base cost would fall within this range. A higher IRR means a greater expected profitability and higher cost of hydrogen to attain that. The band widens at higher IRR due to a greater sensitivity to initial capital investment on expected returns.

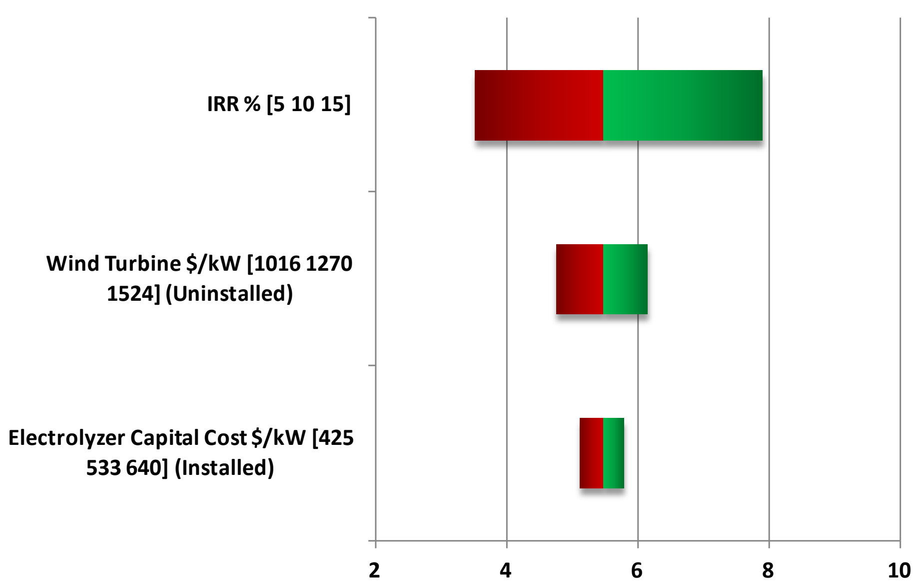

Figure 16. Hydrogen production cost sensitivity to select variables

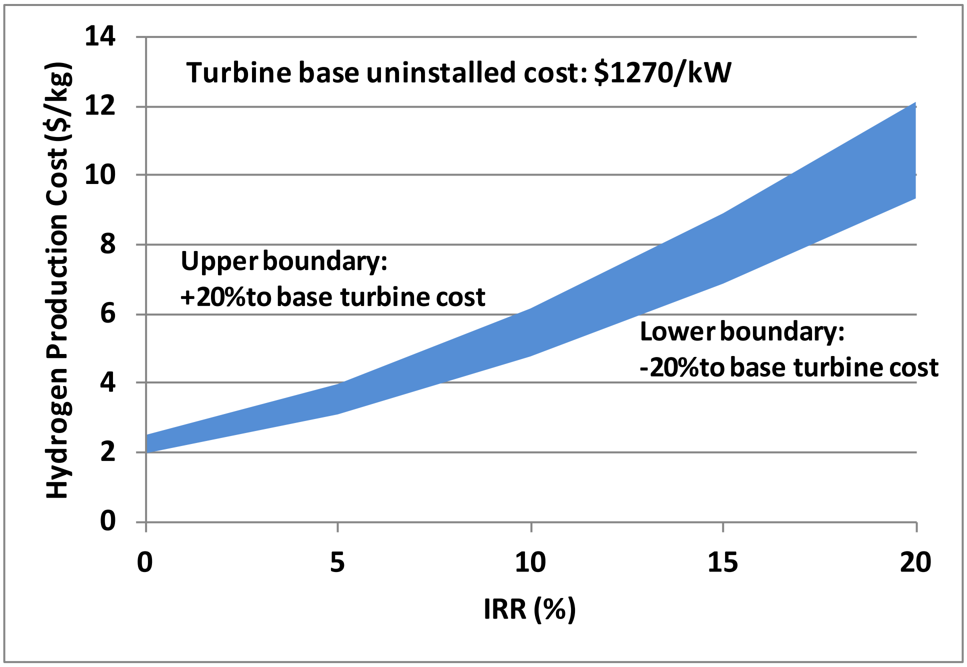

Figure 17. Range of hydrogen production cost sensitivity for increasing rate of return (IRR)

In the base case no incentives were assumed providing an unsubsidized cost of hydrogen. However, given current policy to promote various renewable energy pathways some incentives might be available to a project such as this. Sensitivity was run on two forms of incentives, the investment tax credit (ITC) and the production tax credit (PTC).

The ITC allows for a corporate tax credit on the initial capital expenditures of a project. The tax credit is relative to the installed size of the project. According to the DSIRE database of incentives the current federal Business Energy Investment Tax Credit applies for small wind projects (< 100 kW), but it was subsequently modified by the American Recovery and Reinvestment Act of 2009 to include projects eligible for the federal PTC to take this ITC instead [43, 44]. Neither of these tax credits applies to hydrogen production via electrolysis, however in order to show ranges of the effect of different policies we have run sensitivity analysis for the turbine and electrolyzers capital costs separately and then combined them. Figure 18 shows the baseline case compared to the three breakdowns of capital costs from 0% to 30% ITC. The ITC is applied to the direct capital costs and the corresponding portion of other capital costs for the turbines, electrolyzers, and combined. No maximum limit to the credit has been applied.

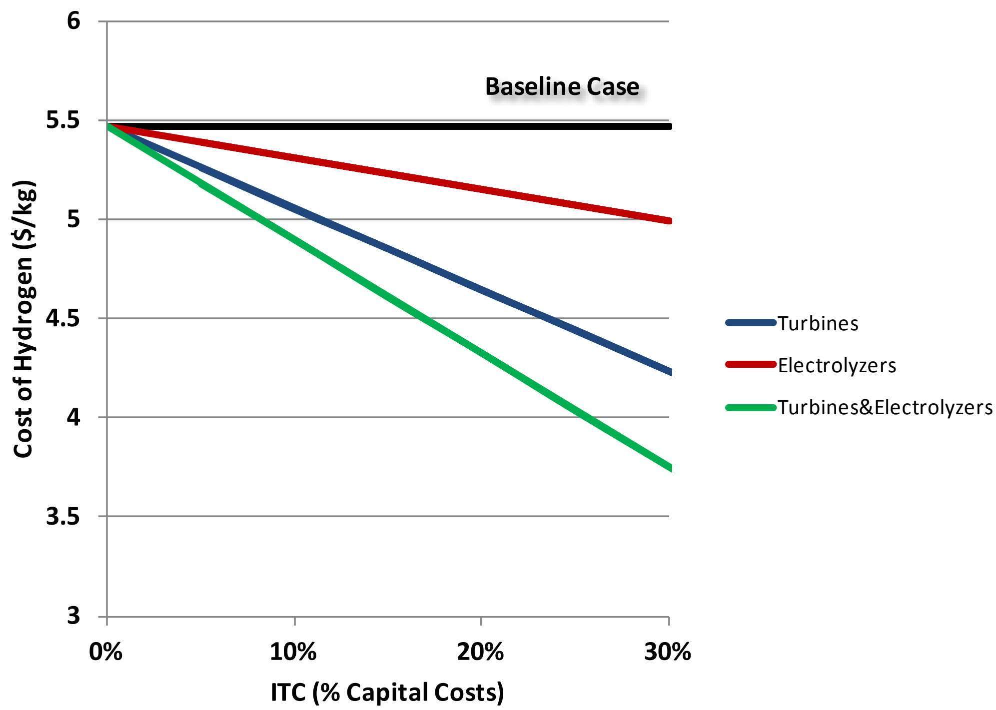

Figure 18. Hydrogen cost sensitivity to 0-30% ITC on select capital costs

A 30% ITC applied to the wind portion of the capital costs reduces the cost of hydrogen by 22% to $4.2/kg, the electrolyzer alone by 9% to $5/kg. The contribution of each part to an ITC applied to both together is in the same proportion as the installed capital costs of turbines and electrolyzers shown in Figure 14. Another consequence to consider is that of a maximum limit to the ITC which could have a large impact on the resultant reduction to the cost of hydrogen. At 30% with no limit the wind ITC is worth approximately $480/kW. If a maximum credit of $200/kW was placed on the turbines it would reduce the impact of the credit to less than the 15% level shown in Figure 18. A $200/kW maximum ITC for the turbines would decrease the cost of hydrogen to $5/kg, a $0.50/kg reduction to the base case of no incentives.

A PTC applies to the actual production of a system. Current federal policy applies to several renewable electricity sources including wind power at $0.022/kWh for the first ten years of operation [44]. The electricity generated must be sold to the hydrogen production system as a separate entity. Several levels of incentives are shown in Figure 19 between $0/kWh and $0.022/kWh which has been applied for the first ten years of operation only. The wind PTC compares slightly unfavorably to the ITC for turbines with the cost of hydrogen being about $4.4/kg for a PTC of $0.022/kWh and $4.2/kg for an ITC of 30% no maximum. The two major factors which could change this are a maximum limit to the ITC or the PTC applied to more than the first ten years of operation.

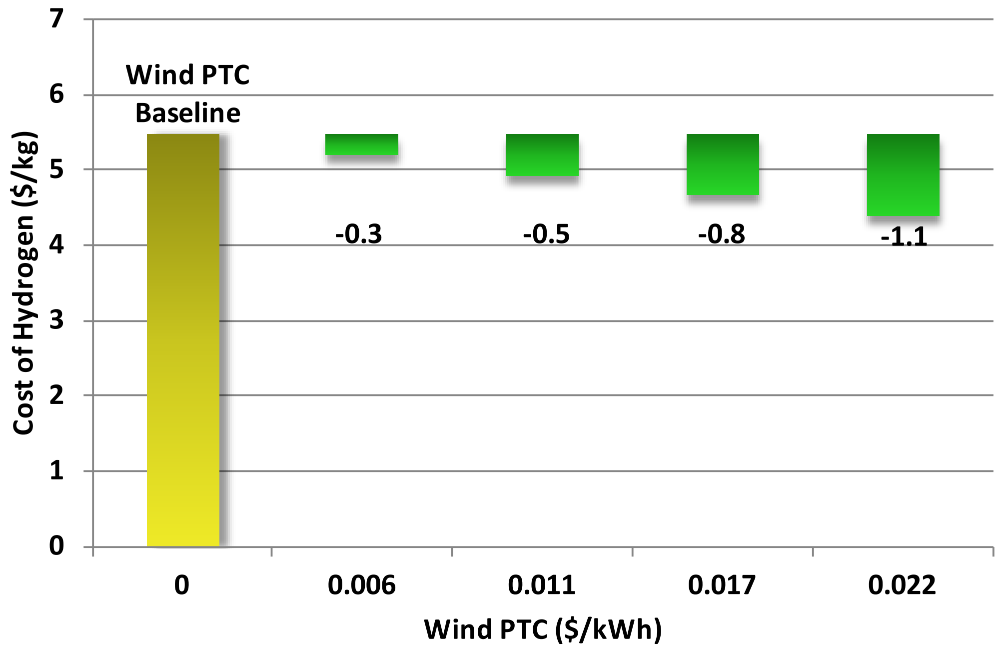

Figure 19. Effect of wind PTC on cost of hydrogen

There is not a directly applicable PTC for the hydrogen produced in this particular case study. However, two other PTC credits are used as a basis for examining the effect on the cost of hydrogen. The Alternative Fuel Excise Tax, expired December 2011, and the Hydrogen Fuel Excise Tax, for liquefied hydrogen, both have incentives of $0.50/gal [45]. By energy content 1 kg of hydrogen is approximately equivalent to a gallon of gasoline (gge) and for this analysis a maximum PTC on hydrogen production of $0.50/kg over the first ten years of operation is considered. Figure 20 shows the hydrogen PTC at various levels compared to the baseline case of no incentives. The reduction in cost of hydrogen from the PTC applied to hydrogen production is about half that of the PTC for wind.

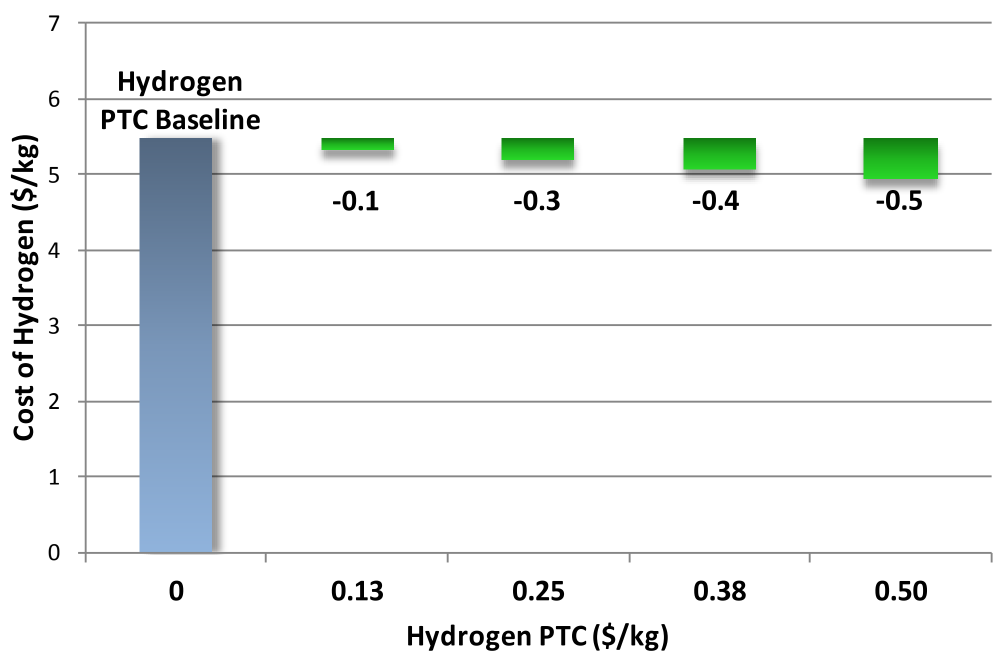

Figure 20. Effect of hydrogen PTC on cost of hydrogen

4.2. Storage and Delivery Costs

Total delivery and storage cost is $3.9/kg of hydrogen for the base case delivery scenario employing compression-less refueling station and assuming useable portion of hydrogen per truck as 80-90% (as our estimated result showed, see details in Section 3.6). Figure 21 shows the dependence of the total delivery cost on useable portion of hydrogen per truck-trailer. The delivery cost presented here is the dispensed hydrogen cost from production plant gate to vehicle.

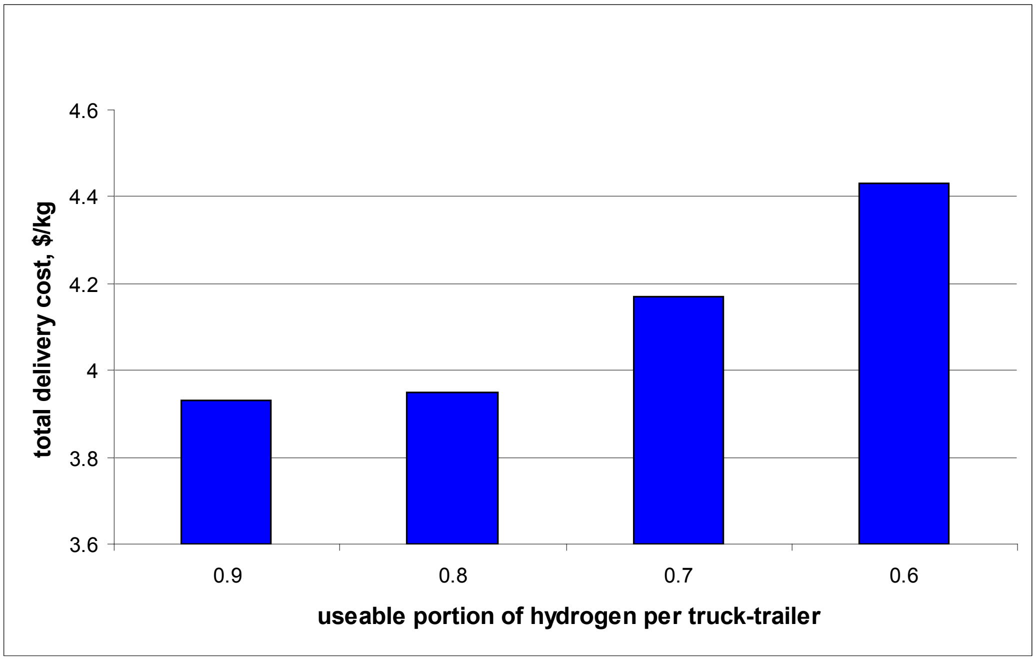

Figure 21. Dependence of the total delivery cost for the base case scenario using 350 bar compression-less station on useable portion of hydrogen per truck-trailer

The total delivery cost for the other delivery pathways employing 350 bar and 700 bar conventional hydrogen refueling stations is compared with the base case scenario on Figure 22. The delivery cost increases by $1.0/kg in the case of 700 bar conventional station.

Figure 23 shows hydrogen delivery cost breakdown between various storage and delivery components. Cavern storage and compressors account for 36% of the total hydrogen delivery cost. Truck delivery takes 43%, while truck compressors, buffer storage and refueling station have lesser contributions in the amount of 10%, 5%, and 6%, respectively.

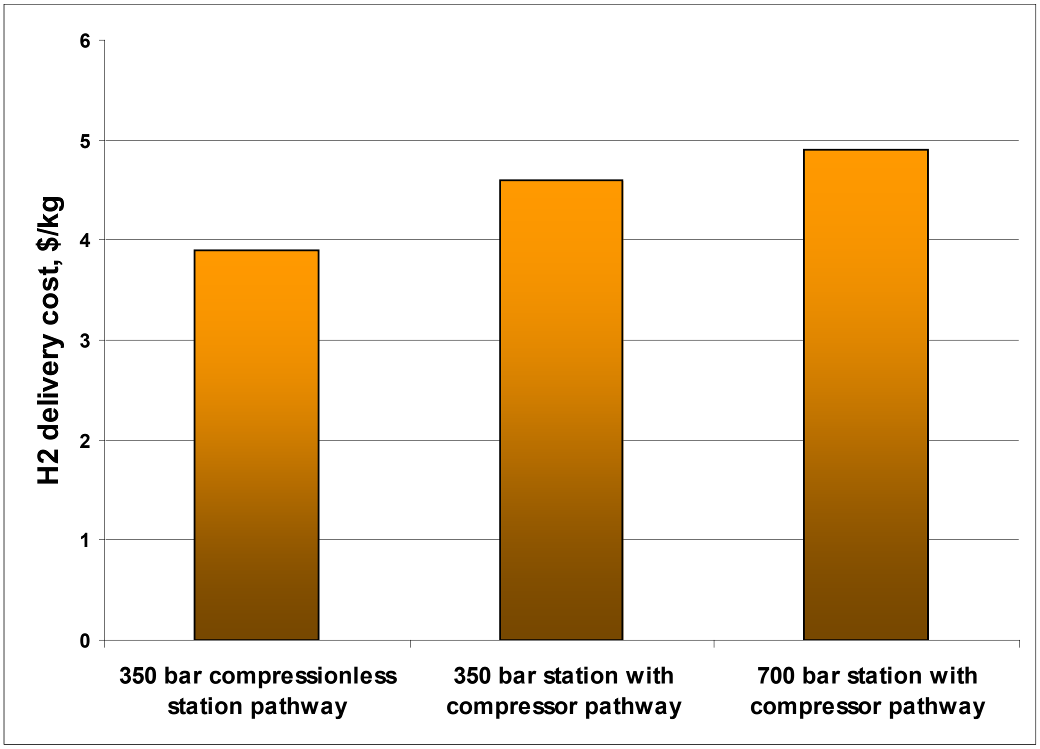

Figure 22. Dependence of the total delivery cost on type of a delivery pathway

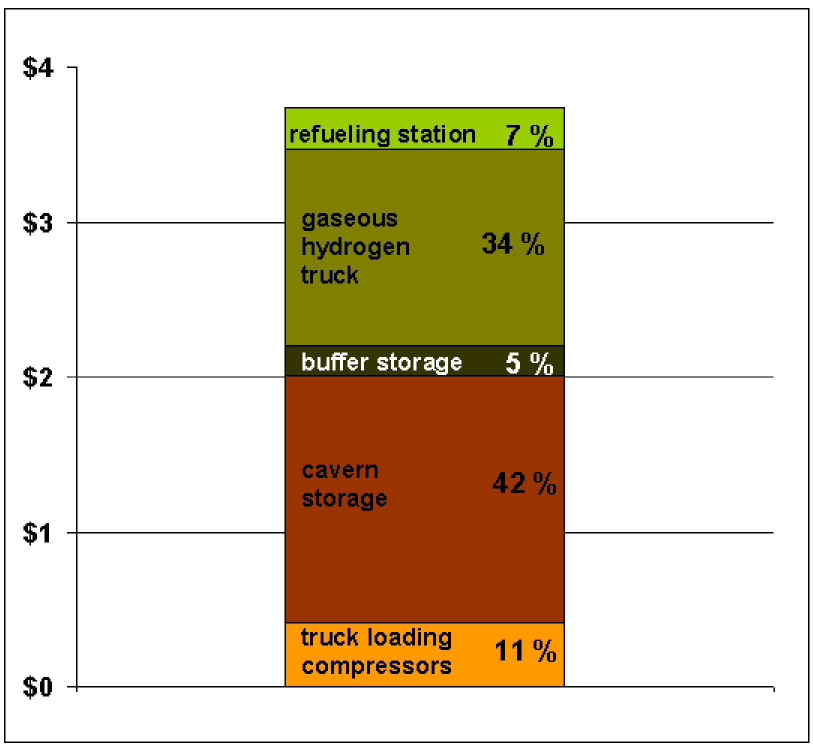

Figure 23. Hydrogen storage and delivery costs for the base case scenario

In our scenario the truck terminal is co-located with the production plant for logistics ease. It includes storage onsite. The total initial capital investments and replacement costs over 20 years of the project lifetime for the delivery equipment are shown in Table 6 and Table 7. The total delivery block investments for the base case scenario are about $144 MM. The costs for separate delivery components are discussed below.

Table 6. Initial capital investments (base case)

Delivery Pathway Component	Capital Cost
Terminal	$139 MM
Truck-Trailer	$4.6 MM
Refueling Station	$191 K

Table 7. Replacement Costs over 20 years (base case)

Delivery Pathway Component	Replacement Cost
Terminal	$0
Truck-Trailer	$242 K
Refueling Station	$28 K

Terminal installed capital investment costs are shown in Figure 24. Cavern is the most expensive part (77%) of the total $139 MM terminal installed capital cost. Truck compressors, buffer storage, and terminal remainder (piping, headers, plumbing, electrical, buildings and structures) capital contributions are 13.2%, 9.5%, and 0.3%, respectively. The terminal also has other capital costs accounting to $13.4 MM which include land, site preparation, engineering and design, project contingency, up-front permitting, and other owner costs. All terminal components have 20 years lifetime. Therefore, there no replacement costs during the current analysis period of 20 years.

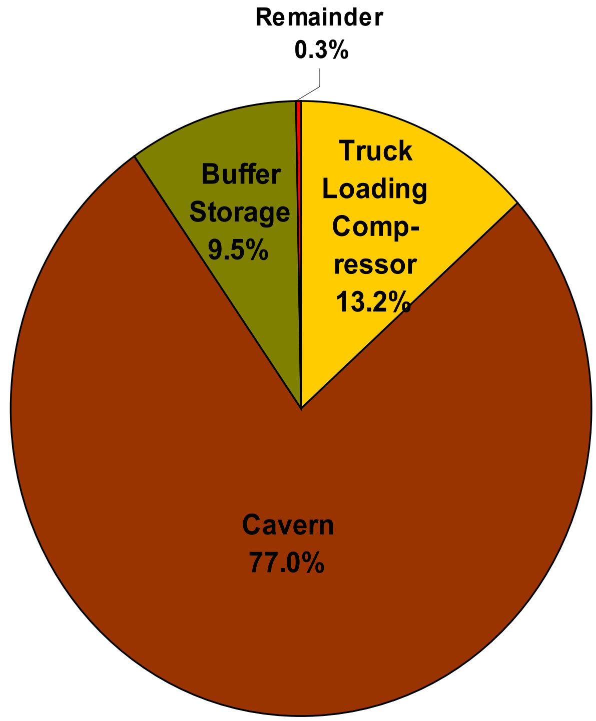

Figure 24. Terminal initial installed capital investments ($139 MM)

The total truck-trailer initial capital investment in the base case scenario is $4.6 MM and the replacement cost over 20 years of a project lifetime of $240 K.

Figure 25 shows the refueling station total capital investments depending on the type of the station. Refueling station capital investment in a base case scenario (compression-less station) is significantly lower at only $191K than for the conventional 350 bar and 700 bar hydrogen refueling stations ($1.7 MM and $2.1 MM, respectively). Delivering hydrogen in high-pressure tubes allows for a very simple station design which lacks compressors and cascade storage, and has only dispenser and control and safety equipment onsite. As seen in Figure 26, control and safety equipment, and dispensers cost 69% and 31% of the total refueling station capital investments, respectively. The replacement cost is due to dispenser replacement only and is $27.5 K during analysis period of 20 years.

Annual costs per refueling station (Figure 27) are also lower for the base case scenario ($65K) compared with 350 bar and 700 bar conventional stations ($129 K and $178 K, respectively).We are comparing the costs for the other refueling station configurations here as the current existing stations in California use compression for vehicle filling.

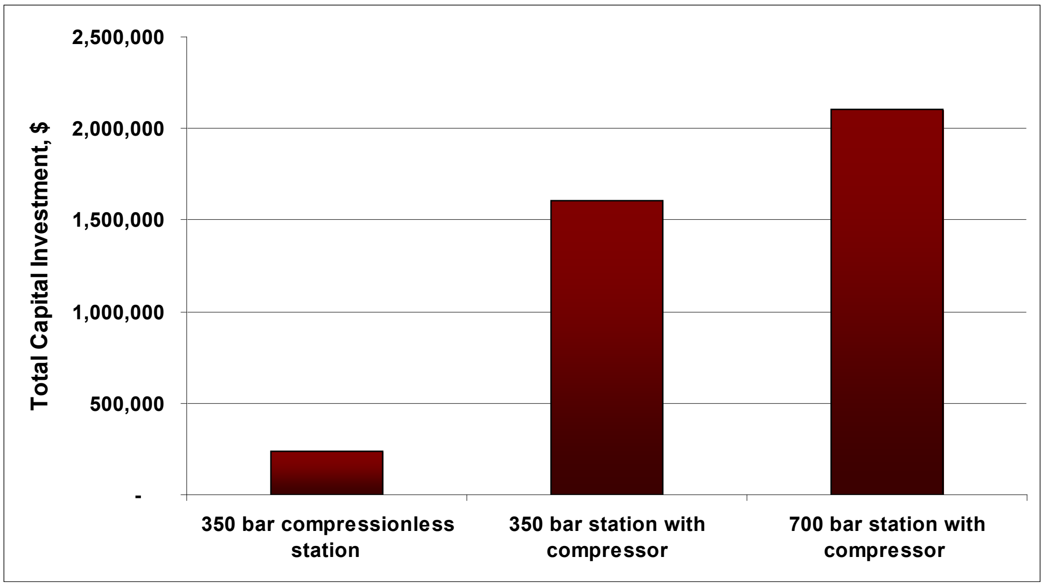

Figure 25. Refueling station total capital investments for various types of stations

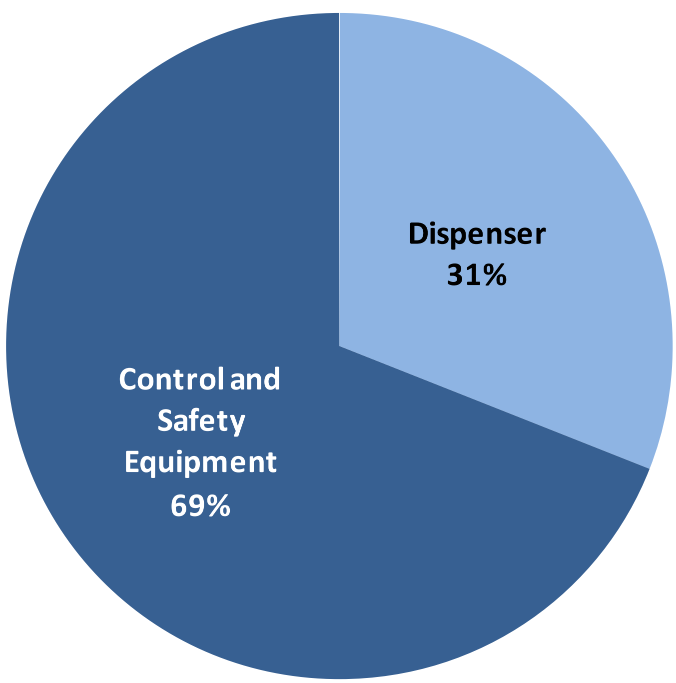

Figure 26. Refueling station installed capital investments ($191K)

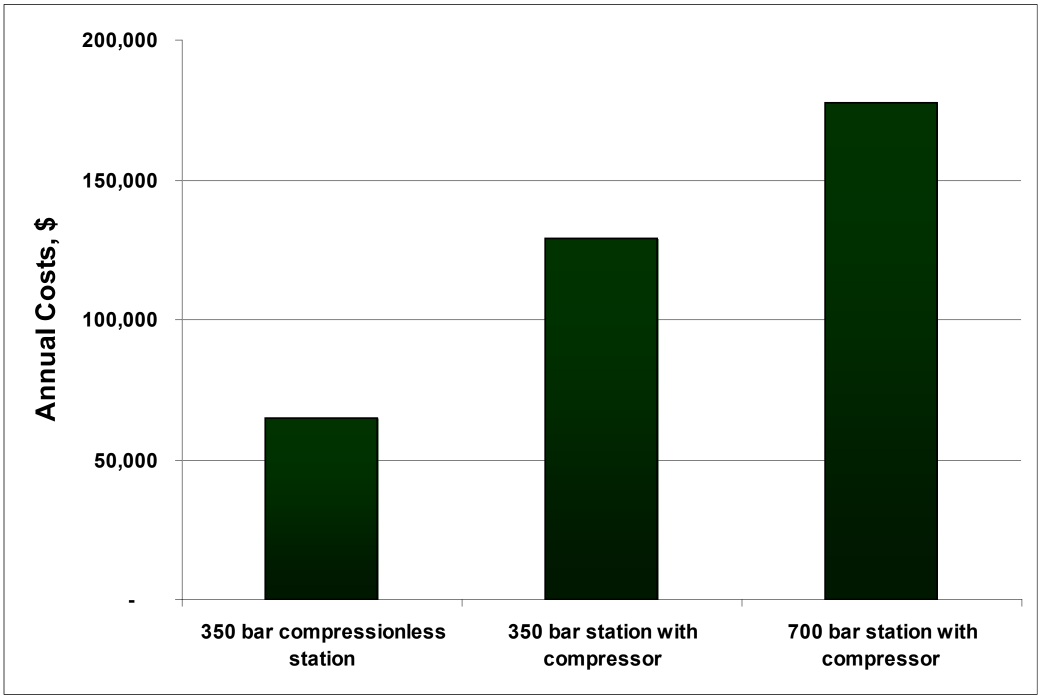

Figure 27. Refueling station annual costs for various types of the station

4.3. On reducing hydrogen cost and initial capital investments though decreasing storage size

Hydrogen cost is dependent on many parameters. One of the biggest factors in the cost is the size of storage required. This storage cavern size is a consequence of the individual wind profile, size of wind turbines and electrolyzers, and the hydrogen demand, i.e. production rate over the year and demand rate. In our case study with wind turbines and electrolyzers rated at 183 MW and a 40,000 kg/day demand the cavern size was about 32 days of the demand. This was enough to capture hydrogen during higher production times to meet demand during lower production times over the course of the year, essentially meeting a flat seasonal demand with a variable production rate.

The four sized elements of the independent wind-hydrogen system (turbines, electrolyzers, cavern, and demand) are optimized to work together over an annual hourly profile. The electrolyzer is sized equally to the turbines in order to make use of the full wind capacity. The turbine capital cost is a greater proportion to the overall project making its energy output very valuable. Downsizing the electrolyzer would mean some wind power is not captured in our stand-alone wind-electrolysis case study. A grid-connected project could mitigate this, but the ramifications of the grid connection add complexity and were outside the scope of the project. The cavern size is determined based upon the variable wind turbines to electrolyzers hydrogen output and the daily demand. While caverns are a large portion of the delivery cost downsizing the caverns would mean not meeting the average demand and could also mean lost hydrogen production when the turbines and electrolyzers are producing, but the cavern storage is full. Hydrogen delivery costs and the operations costs for the turbines and electrolyzers is less compared to the installed capital cost of the production equipment making the project more profitable when it can run.

For demonstration purposes, we ran an additional scenario optimizing for smaller daily hydrogen demand of 30,000 kg/day. Allowing for more variability in the quantity of hydrogen delivered can reduce the cavern size. This resulted in the electrolyzer and wind farm decreasing to 75% of their baseline and the size of the cavern also being reduced. In this variation the yearly averaged delivered hydrogen was about 30,000 kg/day though the demand remained 40,000 kg/day. This means that there was more variability in the daily delivered hydrogen, however, it also resulted in an 85% decrease for required storage size. Varying average daily demand can result in very different optimized cavern sizes (for storage required to meet hydrogen need). As a consequence, allowing more variation in demand and lowering yearly averaged daily demand expectation can also result in significant reduction of initial capital investments due to smaller wind farm, electrolyzer and storage sizes.

The benefits of such downsizing are the following. Production plant initial investments decrease by 23% from \$430.8 MM (base case) to \$331.4 MM. Terminal initial capital investments drop significantly due to storage volume decrease by 57% from \$152.4 MM (base case) to \$65.3 MM. And the size of the storage decreased to less than 10 days, though for the delivery pathway 10 days of storage was assumed.

Production plant optimization for this scenario results in the same hydrogen production cost of \$5.5/kg, but it essentially reduces the storage size (needed to balance spiky nature of wind, see Figure 9, and to meet daily demand) from 32 days (as in a base case) to 7 days. As a consequence, the terminal contribution to the hydrogen cost drops down by \$0.9/kg, resulting in the total storage and delivery cost of \$3.0/kg. Thus, the total dispensed (10% profited) hydrogen cost drops by \$0.9/kg to \$8.5/kg, compared with the base delivered hydrogen cost described in the previous sections.

Thus, downsizing the wind farm and storage size to fulfill decreased demand of 30,000 kg/day gives us \$0.9/kg drop in hydrogen cost and 32% decrease in the initial capital investments. However, the production plant now delivers a more variable quantity of hydrogen as well which averages over the year to 30,000 kg/day. The additional scenario shows that the amount of bulk storage, and therefore delivery costs, can be greatly impacted by the margin of acceptable variability in met demand.

5. Conclusion

This case study utilizes a full hydrogen production and delivery pathway with specific sites in order to understand the different cost mechanisms for a central renewable hydrogen production and delivery system. It is not the only renewable hydrogen production pathway, but wind does represent one of the fastest growing sectors of renewable energy. Furthermore, a standalone wind-to-hydrogen plant is both scalable and could be situated in other locations. The wind site chosen has a very high wind capacity of 43.2%. Given comparably good wind, the results would be expected to be similar as there were other similar sites in the region chosen. One aspect which might vary is the size of the storage which is based upon the production and demand rate. In a standalone wind-to-hydrogen plant the production rate is tied to the variability of the wind profile. Matching the variation of the production rate over the year to the demand produces the required storage size. In this analysis we had 32 days of worth of storage to meet the 40,000 kg/day demand. The hydrogen produced from a wind site near the Mohave Desert and delivered to and dispensed at the Los Angeles refueling stations costs \$9.4/kg in 2010 dollars, \$5.5/kg from the production plant costs and \$3.9/kg from the storage and delivery costs for the base case scenario employing compression-less refueling station. The total delivery cost for the other delivery pathways employing 350 bar and 700 bar conventional hydrogen refueling stations increases by \$0.7/kg and \$1.0/kg, respectively.

A significant portion of the production cost comes from the wind turbines which have shown a fair bit of variability. With wind turbine sector growing rapidly, the turbine cost may drop even further so that it would only benefit this system.

While the cost of delivered hydrogen is not inexpensive several things should be considered. The cost of hydrogen given here includes a 10% IRR which means it is a profited cost; it includes a rate of return on investment on top of the basic costs of hydrogen. The costs presented here also do not include any kind of tax credit or other incentive for clean, renewable fuel. Finally the on road fuel economy of FCEV currently in development is around 40-50 miles per kg hydrogen which is almost twice as high as for the average on-road gasoline vehicle [16]. Depending on the cost of gasoline in the coming years, this may make renewable hydrogen more competitive as a vehicle fuel.

The sensitivity of the cost of hydrogen can have several factors. On the production side IRR, capital costs, and incentives can all have an impact. An IRR of 20% can raise the cost of hydrogen to $10.8/kg. While a turbine capital cost of ± 20% can result in a range from $4.8/kg to $6.2/kg for the production costs. The base case includes no incentives, but an ITC or PTC on the wind energy can reduce the production side cost of hydrogen to $4.2/kg or $4.4/kg, respectively.

This analysis includes a concrete example in California using real locations to show one example of a central renewable hydrogen production and delivery pathway capable of satisfying a 1% FCEV penetration. The system also provides further flexibility in the electricity sector by adding options to wind development. The system can help reduce greenhouse gas emissions and air pollution in the transportation, electricity, and even perhaps some industrial sectors. This will be important as policy converges on regulating the energy system for California to satisfy clean energy goals. SB1505 (environmental regulations for the production of hydrogen) already includes requirements that one third of hydrogen come from renewable sources and acknowledges goals which crisscross sectors.

As demand increases, central production may be one way in which to curb production costs. Strategic use of excavated cavern storage could also drive down some of the delivery cost which included the cost for this storage at the truck terminal. Wind cost, policy incentives, transportation improvements, and clean energy demand may improve the conditions for renewable hydrogen production.

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