RENEWABLE HYDROGEN FROM WIND IN CALIFORNIA

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1. Introduction

Hydrogen produced from renewable electricity sources is frequently touted as the long-term goal for the hydrogen economy. The purpose of this paper is to examine the technical and economic realities of using wind power to produce hydrogen on a large scale in the state of California. Because of the relatively clean electricity grid, and its work on development of a hydrogen highway, California provides a near-term opportunity for examining a renewable hydrogen future.

This paper examines the results of a techno-economic model of several major wind resources and electric utility demand profiles in California which looked at sizing and cost implications for hydrogen station components as well as various control strategies for maximizing the benefits to the local utility grid. In addition to the technical questions regarding the nature of the wind resource and the electrical grid, economic sizing of electrolysis systems will be optimized to maximize the utilization of the capital-intensive electrolysis systems. The economic analysis includes the entire wind hydrogen pathway in both the near and long-term in order to understand what the optimum sizes and capacity factors are that will allow integration with the existing grid and wind resource while minimizing the cost and environmental impact. The economic analysis uses current quotes for prices of equipment with sensitivity analyses to capture future technological improvements.

The technical and economic analyses are part of a larger model of renewable hydrogen production in California, which also looks at the environmental impacts of renewable hydrogen in order to understand the best-use issues for renewable electricity and the potential benefits or drawbacks of a renewable electrolytic hydrogen pathway. This environmental aspect will be addressed briefly in the paper, identifying break points for renewable energy and grid mix in order to ensure no backsliding of emissions, as well as looking at implications for the best use of wind energy in an unconstrained grid.

The model that has been developed uses hourly data from 3 wind sites and 4 electric utilities in California, as well as emissions profiles from the EPA's Egrid Emissions Database. The granularity of the hourly data allows detailed analysis of various control strategies. In particular, peak demand and low wind periods are examined to determine what impacts the sizing of the electrolysis loads will have on the electricity grids and how hydrogen storage can be balanced with the need to supplement the renewable electricity source with grid power.

1. University of California, Davis, Institute of Transportation Studies: Hydrogen Pathways Program

2.0 Technical Analysis of Wind Hydrogen Production in California

2.1 Wind Resource Availability

The state of California possesses a significant quantity of renewable resources which could be harnessed for the production of electricity and hydrogen for transportation. The scope of these resources were quantified in the California Energy Commission's Renewable Resource Development Report (RRDR) [1], which was developed in order to identify the available renewable resources for the California Renewable Portfolio Standard. The RRDR showed more than 260,000 GWh of renewable resources that could technically be captured by California utilities to meet their renewables obligations. This compares to the total electricity consumption in California of 256,000 GWh of electricity in 2003. In addition, approximately 3.7 Million GWh of renewables are technically feasible for capturing in the entire Western grid region according to the RRDR. Of these resources, wind electricity was the largest resource in the West, and the second largest in California behind solar.

While the amount of renewable energy sources are significant in California and the West, the characteristics of many of these resources (solar, biomass, geothermal) make them desirable for using on the electricity grid to displace either peaking generation in the case of solar, or baseload fossil generation in the case of geothermal and biomass. Wind energy however does not necessarily provide an ideal resource for the utility markets. While it is currently one of the lowest cost renewable energy source in California [2], wind power characteristics in many of the desirable wind resource areas do not match very well on a diurnal basis with the hourly electricity demand in California [3]. In addition, the intermittency of wind power means that utilities must either have flexible generation that can meet demand when the wind is not available and can turn down when it is, or employ some type of energy storage technology to mitigate the intermittency. If neither of these options are employed, penetration of wind onto the utility grid may be limited, as has been the case with some onshore and near-shore wind installations in several Scandinavian countries and is estimated to cause instability at 20% of the real time demand levels in the absence of accommodation mechanisms. [4]

The available wind resources in California and the Western states far exceed the limits that would be acceptable for grid reliability needs. According to the RRDR, high wind speed sites[1] could provide approximately 44,000 GWh of wind generation per year, and with the inclusion of lower wind speed sites[2], that number would increase to approximately 230,000 GWh per year. This number does not include the extensive offshore wind resources off of the coast of California. In addition to in-state wind generation, in the WECC member states, there are more than 2.8 Million GWH of wind energy available per year if both

1. High wind speed sites refer to class 5 and 6 wind speed sites in which wind speeds average greater than 6.0 m/s on an annual basis at a heigh of 10 meters.
2. Lower wind speed sites refer to class 3 and 4 wind speed sites in which wind speeds average 5.1-6.0 m/s at a height of 10 meters.

high and low wind speed sites are counted. The existence of such a significant amount of wind resource provides a good opportunity to examine the possibility of using the wind in conjunction with electrolysis and hydrogen storage technologies to maximize its utilization.

2.2 Wind Resource Suitability for the Production of Hydrogen

When it comes to the production of hydrogen, the seasonal characteristics of wind energy can be much more difficult to deal with than the diurnal characteristics. If an electrolyzer were to be run strictly from wind electricity, depending on its size in relation to the wind resource, its annual capacity factor might be as low as 30%, depending on the wind resource. In its worst month, an electrolyzer operating off of the Tehachapi wind resource might produce as little as 10% of the output that would occur during the best month. This is significant for hydrogen production because it implies the need for massive amounts of hydrogen storage if the wind produced hydrogen is expected to meet daily vehicle demand throughout the year. Trading off on production with a fossil or biomass based hydrogen source to minimize seasonal storage of hydrogen would result in a fairly low annual capacity factor for the fossil/biomass based hydrogen production technology as well, and may require seasonal storage of those feedstocks.

For all three of the wind resources examined, the diurnal wind resource was significantly weighted towards nighttime and early morning production. From a utility perspective, this is the worst time for the wind resource to be producing, as it is then competing with baseload power, some of which may be difficult to turn down [5]. From the perspective of producing hydrogen, the time of day of production is less important given the ability of hydrogen to be stored, and the possibility of using grid power to supplement the wind power if necessary. If grid power is used to supplement the wind power, operation of the electrolysis unit that resulted in an increase of peak demand for the electricity grid would be highly undesirable considering the poor environmental and economic characteristics of peaking power in California. The ability of grid connected electrolyzers to shut down, and meet hydrogen demand with stored hydrogen produced during off-peak hours would be one attractive way of addressing this issue. However, a tradeoff would need to be made between the number of hours that a grid-connected electrolyzer could be shut down or operated at minimum level, and the annual capacity factor of the electrolyzer. Both of these issues would have significant implications for the cost and environmental characteristics of hydrogen.

2.3 Hydrogen Production and Storage Technical Model

For this analysis, models of the electrolyzer efficiency were combined with compression and power conversion efficiencies to come up with overall hydrogen production efficiencies that varied depending on the hourly capacity factor of the electrolyzer. The electrolysis models were based on two different alkaline electrolyzers from the HYDROGEMS model library [6]. Future efforts will incorporate high pressure PEM electrolysis as a third option. The compression and power conversion efficiencies were taken as constants and did not vary with the hydrogen production rate. This assumption simplified the model, however future efforts will incorporate variable efficiencies for each of these components. With the power conversion and compression incorporated, the efficiency of hydrogen production and compression averaged between 56 and 58 kWh/kg, or roughly 68-70% efficiency on a Higher Heating Value (HHV) basis. While this may be a small improvement over the actual operation of current systems, it is slightly below quoted efficiencies from manufacturers [7] and estimates of efficiencies used in other studies [8]

The daily hydrogen demand assumed a morning and evening peak for fueling such that there were two 4-hour periods during the 15 hour fueling window in which 80% of the vehicles were fueled. Because the evening peak happens to coincide fairly well with California's peak grid demand, a significant amount of additional storage is required. A sample peak day is shown in Figure 2.1, which represents a 154 kg per day station with an 8 hour peak shutdown capability. On the day shown, the grid was above the ONPEAK level for 12 hours.

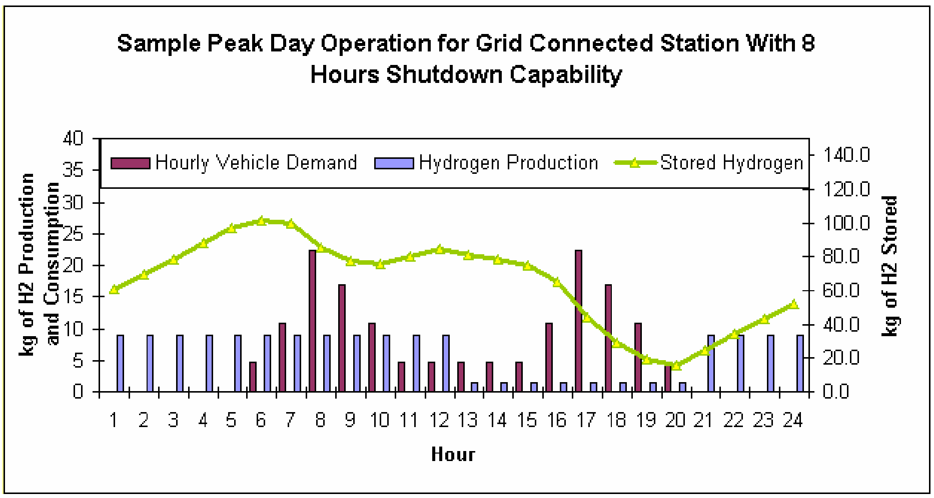

Figure 2.1: Sample ONPEAK Day at 154kg/day Distributed Electrolysis Station

2.4 Operation Scenarios

For this analysis, two different production options were initially examined. The first option was to produce hydrogen at the site of the wind farm and transport it to the end user via truck or pipeline. Due to the significant seasonal differences in wind availability, this option is unlikely to provide cost effective hydrogen until the cost of electrolysis has fallen significantly and the demand for hydrogen has been built up enough to support a pipeline based infrastructure. Looking at a small fleet of 600 vehicles, the amount of storage required to meet the daily demand of the fleet throughout the year would be more than 12,000 kg. This is more than 20 times the amount of storage that would be required if the electrolyzer was to operate at a constant level throughout the year. Without inexpensive geologic storage, the costs of such a scheme would be prohibitive.

As a result of seeing the very high storage costs due to the seasonal variability of the wind in California, it became clear that the second option of a grid-connected distributed electrolysis network might be more attractive in the near term. This network would use the wind when it was available, and the grid when there was no wind. In this way, the storage could be managed to a size that could be deployed in a distributed manner, at the point of use. Each of these two options will be examined in detail.

In the case of a centralized hydrogen production scenario, there are a couple of possible configurations. If the electrolyzer and wind resource are completely stand-alone from the grid, the electrolyzer might be sized to meet the maximum output of the wind farm, or it might be sized at an intermediate level, allowing some wind to spill in order to improve its capacity factor [9]. If a wind resource was serviced by both an electricity grid and an electrolyzer with a hydrogen pipeline, the electrolyzer's size could be smaller than the wind turbine capacity which could improve its capacity factor at the expense of the electricity transmission lines. This would also allow the export of wind electricity during peak demand hours on the grid.

In order to store the hydrogen from a centralized wind electrolysis production scenario, significant seasonal storage would be necessary. The only feasible technology for storing large quantities of hydrogen seasonally would be geologic storage. If the Tehachapi wind resource were fully built out and used entirely for hydrogen, the amount of geologic storage required would be approximately 50 billion scf in order to serve a fleet of 3 million vehicles. By comparison, California had 446 billion scf of geologic storage capacity for natural gas in 2003, nearly all of which was in depleted gas fields [10]. There is a fairly wide distribution of oil and gas fields in California [11] that potentially could be used for hydrogen storage depending on their geologic makeup. One difficulty here is that a significant amount of hydrogen demand would need to be built up before large-scale geologic storage and pipeline transport would be feasible. While it is possible that the demand could come from oil refineries and chemical manufacturers, it is unlikely that the wind hydrogen would be cost competitive with large-scale natural gas SMR until natural gas prices were significantly higher.

Storage of hydrogen in a pipeline is a possibility if the purpose for the storage is for mitigating either diurnal or very short duration variations. For example, a 36" 1000 mile pipeline, at 7 MPa capable of transporting 2,400 Tonnes of hydrogen per day would allow for approximately 1 day of storage in the pipeline, based on

[12,13]. Because this analysis looked primarily at wind resources in California, pipeline distances would be much shorter, for example, 100 miles from Tehachapi to Los Angeles. As a result, the amount of hydrogen that could be stored in the pipeline would be closer to a few hours. It should also be noted that such large pipelines for the transport of hydrogen have not been constructed. The largest pipeline sizes for hydrogen transport currently in operation are from 8-12 inches in diameter, and are capable of moving 240 Tonnes of hydrogen per day, or enough hydrogen to fuel a fleet of 440,000 fuel cell vehicles [14].

The second option that was examined for production of hydrogen was the distributed production model where the wind electricity is transmitted onto the grid and hydrogen is produced at the station with onsite hydrogen storage. This option has the advantages of modularity and flexibility, allowing infrastructure to grow with demand more easily. Furthermore, in the early years when electrolyzer costs are high, grid-connected electrolysis allows for higher capacity factors of the electrolyzer units, thereby minimizing their cost influence on the price of hydrogen. Considerations of the environmental impacts of the electrolytic hydrogen put restrictions on the amount of grid electricity that can be consumed. Also, the access that a station owner might have to low electricity rates is fairly limited, considering that station sizes would likely not exceed more than 1-2 MW of electrical demand. As a result, the operations mode of the station would need to be such that it was of benefit to the utility in order to provide justification for access to lower rates. Scenarios for station operation included 100% capacity factor operation, and grid peak shutdown in addition to the wind-only operation that was described above.

By varying the station size, and the amount of time that the electrolyzer could shut down while still meeting demand, it was possible to increase or decrease the ratio of wind to grid electricity, which had implications for the cost and environmental characteristics of the hydrogen. This can be seen in Figure 2.2,

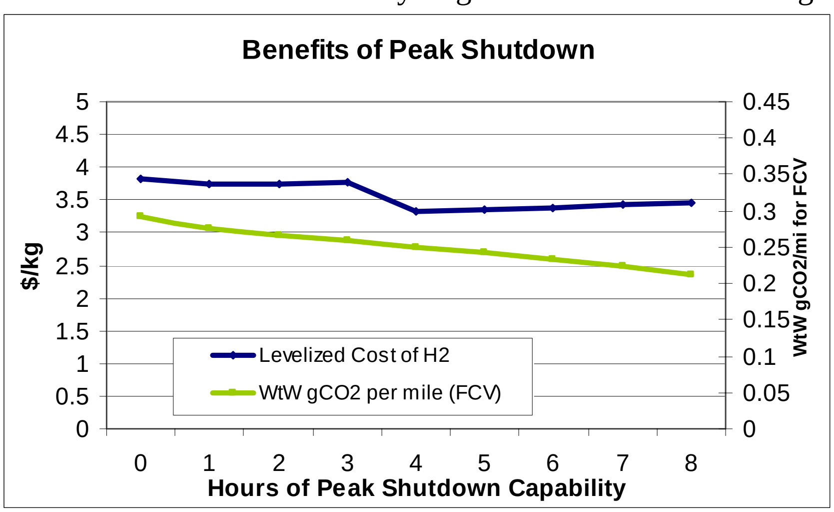

Figure 2.2: Impacts on Hydrogen Costs of Peak Shutdown Capability

which shows how the increasing wind energy reduces the cost and CO_2 emissions associated with the hydrogen. Also significant here is the Demand Side Management (DSM) value that applies once more than 4 hours of storage/shutdown capability are reached.

The key variables that impacted the capacity factor of the electrolyzer were the number of hours that the electrolyzer could be shut down when the grid required it, and the threshold at which the grid might request the hydrogen station to curtail load. Figure 2.2 shows the load duration curves for each of the 4 utilities examined over a 12-month period between September 2002 and August 2003. Based on the inflection point for the larger investor owned utilities, a 70% threshold was used for designating ONPEAK grid demand. In the model, if the station was capable of shutting down for 6 hours, and there were more than 6 hours of ONPEAK grid demand that day, the station would shut down for 6 hours centered around 5:00 PM, which was the peak demand hour in California over the period examined. If the number of ONPEAK hours were smaller than the number of hours that the station was capable of shutting down, the station would stop production of hydrogen for the number of ONPEAK hours for the day. Any time the station produced hydrogen for fewer than 24 hours, the production was shifted to the OFFPEAK hours, resulting in the need for a larger electrolyzer and storage capacity to ensure the ability to meet the daily hydrogen demand. During the ONPEAK hours, the electrolyzer would maintain a minimum load in order to be ready to ramp up production. An analysis of the cost tradeoffs is examined in the economic analysis.

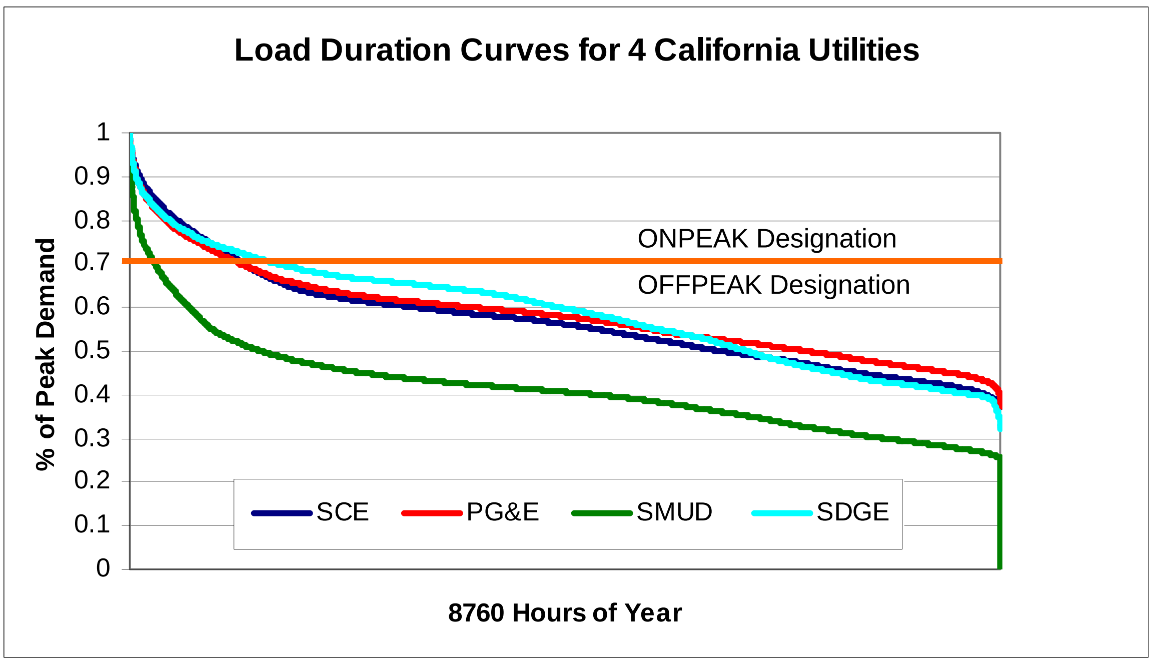

Figure 2.2 Load Duration Curves of Several Large California Electric Utilities

The impacts to the grid depend on the quantity of hydrogen production that has been deployed. Because the demand for transportation demand is not likely to become significant for many years, examining the impacts on the grid require looking at scenarios where there is a high penetration of fuel cell vehicles and significant buildout of California's wind resource areas. Because of wind power's intermittency, concern over wind penetration on the grid is such that some sort of storage technology will likely be necessary before grid operators feel comfortable with installed wind capacity going beyond 20% of the utility peak demand capacity. With the possible acceleration of California's Renewable Portfolio Standard to 33% by 2020 [15], and wind power likely to play a significant role with as much as 70% of the new renewable power, 20% penetration of wind capacity could come as early as 2013. If the growth in fuel cell vehicles was assumed to increase by 75% per year starting today, significant demand for hydrogen (1 million vehicles) would not be reached until the 2025 timeframe. Figure 2.3 shows a high growth scenario installed capacity of wind as a result of both the electricity and transportation sectors.

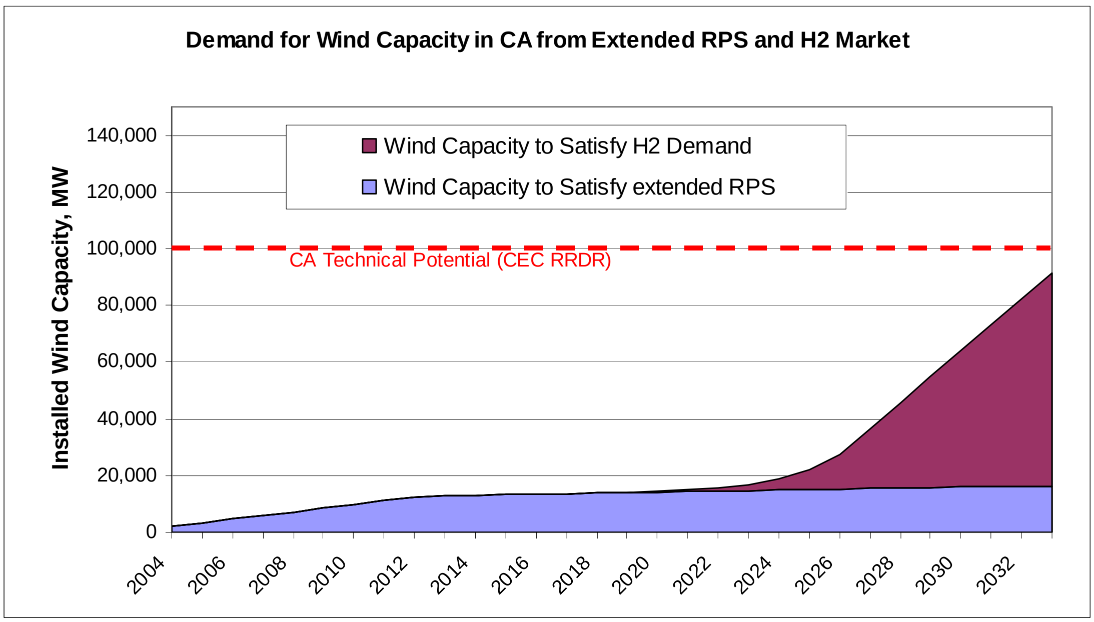

Figure 2.3: High Growth Scenario Installed Wind Capacity in California (20% Grid Penetration Constraint)

In the long term, wind capacity could eventually be built out to levels approaching the technical potentials laid out by the Energy Commission, and with advances in technology, could exceed those levels over the long term. For this analysis, with significant growth in demand for renewable hydrogen, the installed wind capacity could approach the technical potential in the Tehachapi area by 2035 under the most aggressive conditions. The result of such significant wind penetration onto the grid would be that some portion of the wind electricity produced during the off-peak hours would be curtailed, unless there was energy storage or off-peak hydrogen production. In the case off hydrogen production, the ability of the electrolyzer to shut down during the on-peak periods would allow the grid to accept wind onto its grid at night, without requiring additional peaking during the day time. An example of this is shown in Figure 2.4. For illustration purposes, a minimum demand load level is drawn on the plot. If wind production drags the grid load below this level, the wind energy will be curtailed. With the ability to produce hydrogen during these off-peak hours, the wind curtailment is eliminated, without adding to the overall grid peak demand. Under ideal situations, if the utility had direct control over the electrolyzer, the load curve could be smoothed out more evenly during the daytime to avoid the valleys created by cycling the electrolyzer from full load to minimum load.

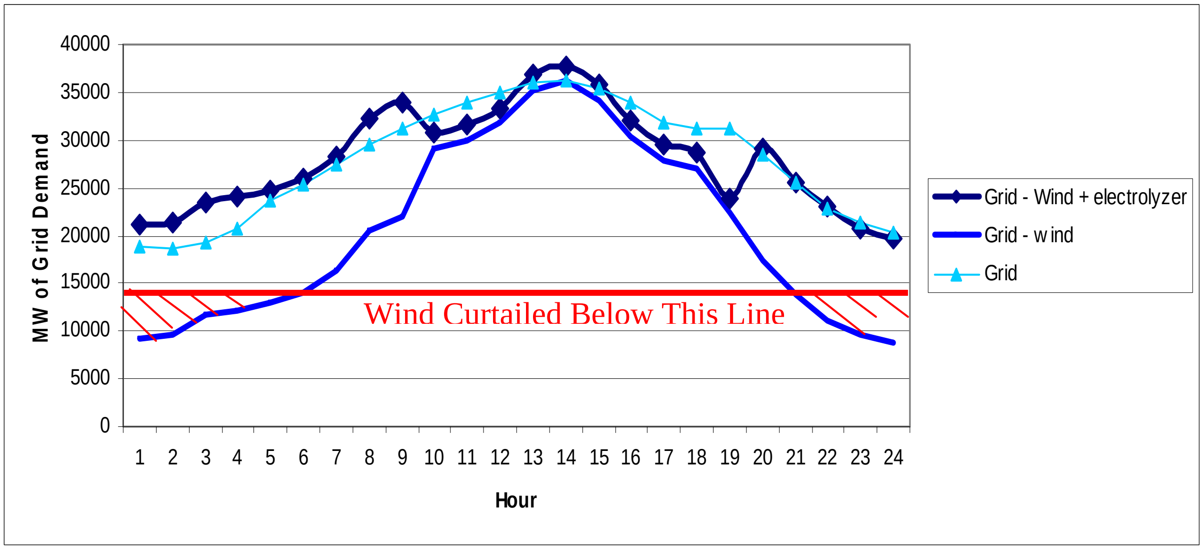

Figure 2.4: Impacts of Off-Peak Electrolysis on a Typical Peak Demand Day in Southern California

3.0 Economic Analysis of Wind Hydrogen Production in California

3.1 Near Term Cost of Wind Hydrogen

There are several important factors which make up the cost of hydrogen. Among the two most significant are electricity and capital costs. For the near term, the electrolyzer dominates the capital costs, while all of the capital costs combined are much smaller than the electricity costs. Table 3.1 shows the assumptions for the capital costs and lifetimes, and Figure 3.1 shows how those costs compare to the electricity costs for a kg of hydrogen after being amortized over the life of the equipment. It should be noted that these costs do not represent the selling price of the hydrogen, as they do not include all of the costs for the station in terms of operation, taxes, or profit. However, for comparison to a forecourt Natural Gas SMR station, these costs represent the majority of the costs that would be specific to the electrolysis station. The electrolyzer, storage and compressor costs were taken from a Hydrogen Station Cost Model built by fellow UC Davis Researcher Jonathan Weinert, and represent current cost quotes from industry for low volume production of these units. The wind electricity costs are consistent with values developed by the California Energy Commission [16]. The units were expected to have a 75% utilization factor, that is, the station would be oversized by 33% in order to ensure that customers always had hydrogen available to them.

Table 3.1: Assumptions for Capital and Energy Costs for Electrolysis Station

Capital Costs per unit		Unit
Electrolyzer Cost	900	$/kW
Wind Turbine Cost	900	$/kW
Land Cost	3000	$/acre
Compressor Cost	5000	$/kg/hr
Storage	1400	$/kg
Dispenser	$50,000	per Dispenser
Maintenance Costs per unit		
Wind Turbine	21	$/kW/yr
Electrolyzer	15	$/kW/yr
Compressor	200	$/kg/hr/yr
Storage	10	$/kg/yr
Lifetime of Components		
Electrolyzer	15	yrs
Wind Turbine	20	yrs
Compressor	7	yrs
Storage	15	yrs
Dispenser	25	yrs
Assumed Interest Rate		
Tax Exempt State Bond or MUNI	5.00%	
Assumed Grid Electricity Price		
Offpeak Supplemental Grid Electricity	0.06	$/kWh
Onpeak Supplemental Grid Electricity	0.09	$/kWh
Station Capacity Factor		
Average Daily Utilization	75%	

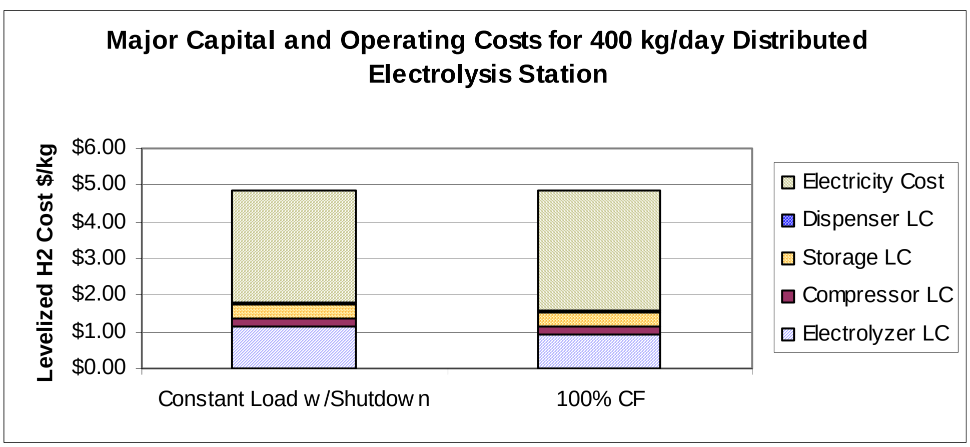

Figure 3.1: Major Capital and Operating Expenses for a 400 kg/day Distributed Electrolysis Station

3.2 Long Term Costs of Wind Hydrogen

Of the components of today's electrolytic hydrogen stations, the electrolyzer has the greatest potential for cost reduction. Estimates for long-term costs of electrolysis technologies range from $300 to $600 per kW [17,18] versus the current costs of around $900 per kW. If PEM electrolyzer technologies are improved to allow longer lifetimes and reliability, costs could drop even lower considering they require many of the same components that would be used in fuel cells for vehicles. These costs are projected to drop to $50 per kW in order to be competitive with gasoline internal combustion engines. [19] While these cost decreases will have some impacts on the price of hydrogen, costs for electricity are not projected to decrease over the next 20 years. While cost estimates from the CEC for wind electricity are shown decreasing over the next 12 years, production will shift from the class 5 and 6 wind sites to the lower production class 3 and 4 wind sites, reducing the capacity factor and increasing the levelized cost of these technologies [20]. Additionally, decreases in the capacity factors of the electrolyzer units due to increased reliance on wind power could mitigate the cost gains achieved by the electrolyzers to some extent.

Once significant demand is achieved for hydrogen, such that several hundred MW of wind will be required for its production, new transmission lines specifically for the production of hydrogen will need to be put in place. The other option is the use of hydrogen pipelines to transmit hydrogen produced at the wind farm to the end users. Either one of these options will entail significant capital expenditures in the hundreds of millions of dollars. In addition, distribution pipelines or electrical line upgrades will be necessary in order to adequately distribute the hydrogen throughout a metropolitan area. Based on rate tariffs for Southern California Edison and Pacific Gas and Electric, approximate Distribution cost charges are $0.001 to $0.01 per kWh [21,22] while transmission charges are one to two orders of magnitude lower. These costs are heavily time dependent for the utilities [23] which lends advantage to distributed electrolysis systems which have the capability to shift demand to off-peak hours.

Based on continued learning for electrolysis systems, it may be possible to achieve significant reductions in cost for grid connected hydrogen systems. Assuming that electrolysis units achieve $200 per kW by 2027, and at the same time improve in efficiency by 10% over that same time period, cost parity with forecourt natural gas systems could be achieved by the end of that timeframe. Figure 3.2 shows a range of costs for forecourt SMR and electrolysis systems, with the low range of the SMR corresponding the EIA projections for commercial natural gas prices, and the high range for the SMR systems corresponding to a California commercial natural gas price with continued supply constraints. The high case for the electrolysis systems corresponds to a 2027 capital cost of $467 per kW, and no reduction in the price of wind electricity.

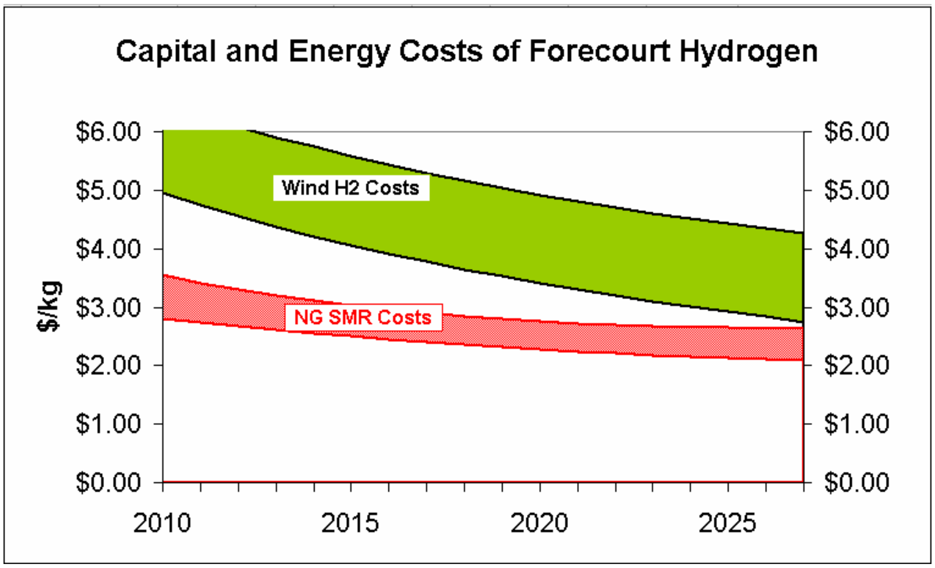

Figure 3.2. Capital and Energy Cost projections of Forecourt Hydrogen

For centralized production of hydrogen at the wind farm, additional costs would include a 100 mi hydrogen transmission pipeline (equivalent to the distance between Tehachapi and Los Angeles), as well as a significant amount of hydrogen distribution lines. While the costs for the transmission pipeline are fairly easy to estimate, the distribution lines are much more difficult as they require knowledge of the spread of stations across each metropolitan region. A recent compilation of natural gas transmission pipeline costs provided an empirical equation for determining the cost of hydrogen transmission pipelines [24]. This equation is as follows:

H2 Pipeline Cost (dia, length) = [924.5(dia)2 + 12,040(dia) + 260,280](length) + 378,750
where (dia) is in inches, (length) is in miles, and Cost is in dollars

This provides a total cost of $189 million for a 36” 100 mile hydrogen pipeline, or roughly $1.9 million per mile. Over a 15-year economic life, such a pipeline would transport more than 13 billion kg of hydrogen. With 10% cost of capital, this would result in a levelized pipeline transportation cost of $0.03 per kg. In addition to the pipeline costs, costs for compression [25] would result in an additional $0.12 per kg including capital and operating expenses. If similar analyses were done for distribution systems along the City of Los Angeles’ major highways, approximately 1000 miles [26] of distribution pipelines would be needed, resulting in pipeline distribution costs of approximately $0.46 per kg for 3” distribution pipelines.

In order to produce wind hydrogen in a central location and meet daily demand, large geologic seasonal storage would need to be employed for the resources examined. The cost for storing hydrogen geologically is estimated at $8.80 per kg of capacity [27]. This would result in storage costs of $0.04 per kg of hydrogen delivered based on full build-out of the Tehachapi wind resource. Figure 3.3 summarizes the costs of long term centralized hydrogen production.

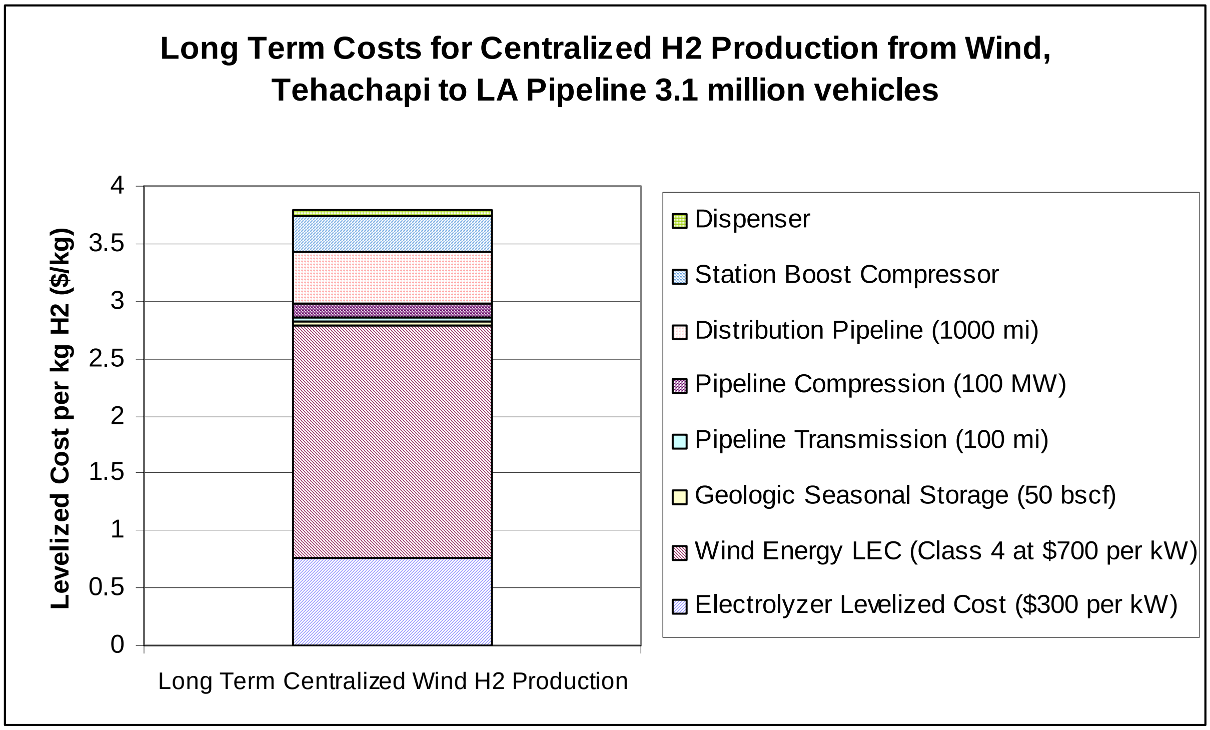

Figure 3.3: Long Term Costs of Centralized H2 Production from Wind

This expected cost for centralized wind production compares to expected costs for centralized NG SMR of $2.25 per kg over the same timeframe. [28] However, if the Tehachapi pipeline and L.A. distribution costs were recovered, as assumed in the final costs for the centralized NG SMR, the resulting cost for the wind hydrogen would be close to $3.00 per kg. While this is still significantly higher than the cost of centralized NG SMR, it is not subject to the same supply issues that natural gas is, which could have an added economic benefit.

4.0 Environmental Impacts Comparison

When considering whether to use wind energy for the production of hydrogen, it is necessary to consider what the environmental benefits will be, as these should be a driver for desiring to do this. While it might seem evident that the benefits would be the offsetting of gasoline use and the associated emissions, the alternative use of the wind energy must be considered. If used to displace fossil resources on the electricity grid, wind energy may have more of an impact on GhG emissions. Of course, this depends significantly on the assumptions of what the wind energy is offsetting in either the transportation or electricity markets. For this analysis, it was assumed that the wind energy was used to produce hydrogen for use in a fuel cell vehicle that achieved various ratios of fuel economy improvement over a baseline gasoline vehicle. The fuel economy of the baseline gasoline passenger vehicle was 27 mpg. The alternative use for the wind, in

California, would have been to offset natural gas generation, as this is the marginal generation resource in California [29]. Because California continues to install combined cycle gas facilities, a fairly low heat rate combined cycle gas facility was chosen as the starting point, at 8,500 BTU/kWh (40.1% efficiency HHV) to represent the marginal generation that wind would offset. If wind were generating primarily during the on-peak hours, it might make more sense to assume it was offsetting peaking natural gas, however that is not the case for the wind resources that were examined. The upstream emissions for both the gasoline vehicle [30] and the natural gas plant [31] were included in the analysis. The analysis used 1 MW of renewable energy and determined what the resulting offset emissions would be. Figure 4.1 shows the break-even line for various fuel economy ratios and combined cycle plant efficiencies.

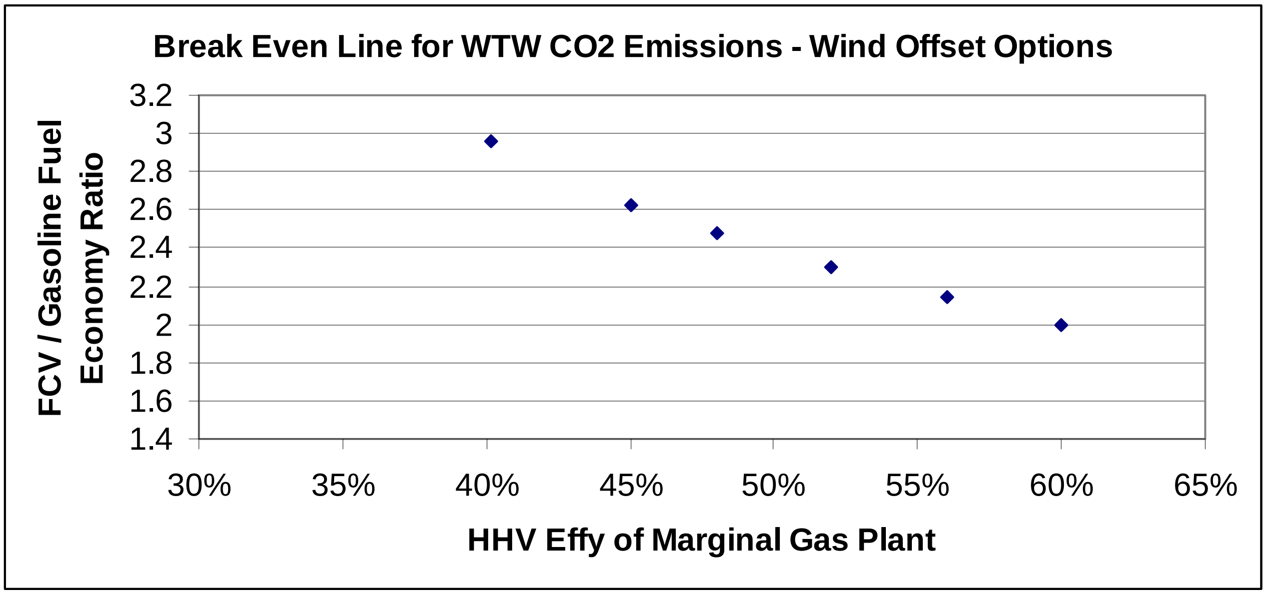

Figure 4.1: Break Even Well to Wheel CO2 Emissions for Transportation vs. Electricity Markets – Wind Offset Options

Based on this analysis, for most conceivable current situations, it would make more sense to offset the natural gas combined cycle plant. However, according to the California Independent System Operator (CALISO), the ability to offset these combined cycle gas plants with intermittent wind generation is quite limited [32] and may result in significant increases in their NO_x emissions and to a lesser extent, their heat rates. [33]. To the extent possible, wind energy should be used first on the grid to offset natural gas plants, however, when facing curtailment due to significant production during off-peak hours, hydrogen production should be considered along with other forms of energy storage.

Because the grid connected electrolyzers used natural gas based electricity to supplement their operation when the wind was not blowing, it is important to ensure that the hydrogen produced does not result in more CO2 emissions, or natural gas consumption than would occur through the production of an equivalent amount of hydrogen via NG SMR. This can be ensured by varying the amount of time that the electrolyzer can be shut down for, and its size in relation to the wind resource. Figure 4.2 shows the break-even line for grid supplemented wind electrolysis in relation to natural gas SMR. The line represents different configurations that would achieve 70% wind power to 30% grid natural gas power. In this case, the SMR was assumed to by 70% efficient.

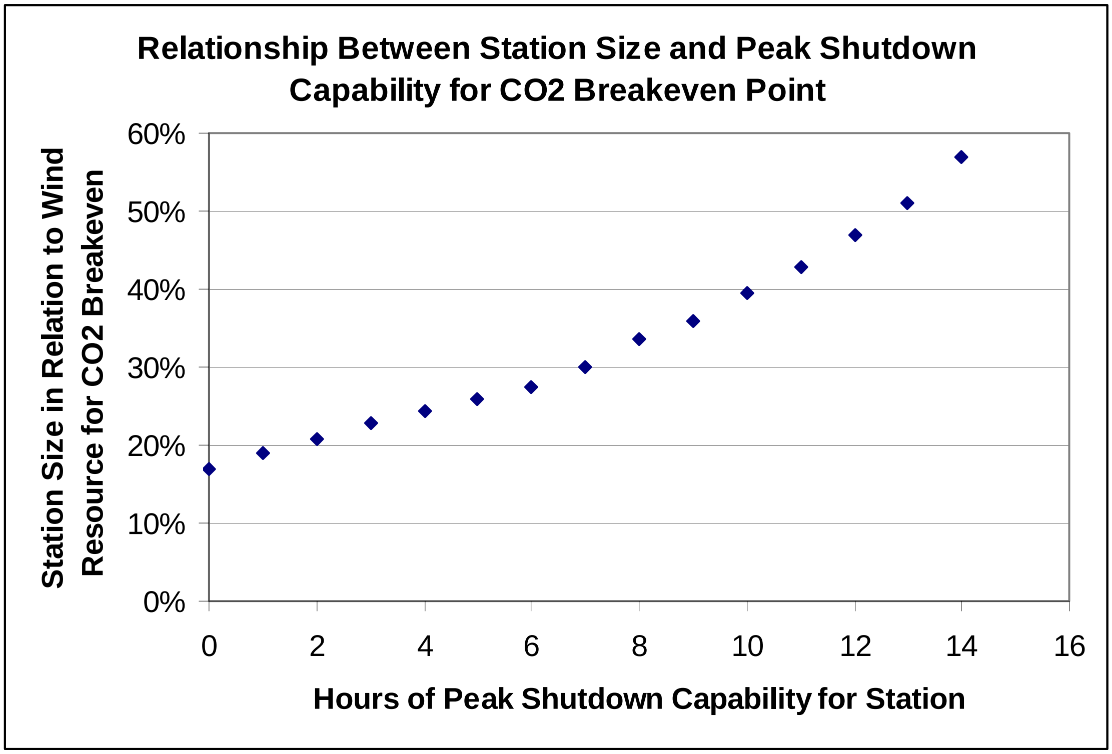

Figure 4.2: Station Size and Peak Shutdown Characteristics for 70% Wind 30% Grid Electrolysis (Break even point for 70% efficient NG SMR)

5.0 Summary/Conclusions

The use of electrolytic hydrogen production systems were considered for both the production of hydrogen for transportation and the maximization of the available wind resources in California. Near term and long term scenarios were examined for the production of hydrogen, using distributed grid-connected electrolyzers in the near-term and comparing these with large scale centralized wind-only electrolyzers in the long term. Different operating scenarios were considered for the grid connected electrolyzers in order to maximize the benefit to the grid and minimize the cost of the hydrogen. The environmental impacts of using wind to produce hydrogen were considered, as well as the tradeoffs between electrolysis capacity in relation to the wind resource and the ability to provide grid peak shutdown service for the utility.

Based on the analysis, the amount of wind energy capacity that could be developed in California without negatively impacting the electricity grid significantly increases if hydrogen production or other energy storage mechanisms can be utilized. The amount of hydrogen that can be produced from the technically potential wind resources in California is 5.4 million Tonnes, which would be enough to power a fleet of 26 million vehicles. While it is quite possible that wind development in California will never approach its full technical potential, the existence of vastly larger wind resources off of the coast of California and in neighboring states provide an opportunity to consider wind energy as a significant contributor to the future transportation and electricity needs of California and the Western states.

Near term costs for grid-connected hydrogen were slightly under $5.00 per kg, without including some of the fixed operating costs that occur at a typical gas station. Longer-term costs for grid connected hydrogen production range from $2.80 to $4.20 per kg. This compares to long term centralized wind electrolysis production costs of $3.00 to $3.75 per kg. The majority of these costs come from the energy required to operate the electrolyzer. Typical efficiencies in the near term were 56-58 kWh/kg, including compression. Longer-term efficiencies were estimated to improve to 54 kWh/kg. These prices were not competitive with centrally produced Natural Gas SMR hydrogen, which could be produced for $2.25 per kg in the long term, however they were close to competitive with forecourt natural gas SMR, which cost $2.10 to $2.75 in the 2025 timeframe.

From an environmental standpoint, the wind electricity would be best used to offset combined cycle natural gas emissions rather than gasoline vehicles unless the efficiency gain between the fuel cell vehicle and the gasoline vehicle was close to 3:1. However, the ability for wind electricity to offset combined cycle electricity generation on the grid is very limited. The CALISO had expressed difficulty with current penetrations of wind electricity on the California grid, and it has been suggested that maximum penetrations of wind electricity onto the grid can be no more than 20% of peak demand without causing problems for the grid. As a result, there is a significant amount of wind potential that will go undeveloped if substantial wind storage or hydrogen production technologies are not utilized. In order to ensure that the hydrogen produced by grid connected electrolyzers is at least as beneficial to the environment as hydrogen produced by NG SMR, no more than 30% of the electricity supplying the electrolyzer can be from natural gas based electricity generation.

By offering control of the electrolyzers to the local electric utility, optimal operations can be achieved such that the grid reliability is enhanced, even with substantial amounts of wind being added. Furthermore, with a significant amount of hydrogen storage, this can be done with a minimum of additions to the transmission and distribution systems as hydrogen production can be limited to off-peak times. While the ability to shut down the electrolysis system implies an oversizing of the components to make up for lost production, costs can be minimized by eliminating high charges for transmission and distribution, as well as peak supplemental electricity prices. In the case of non-utility controlled hydrogen generation systems, these benefits can still be realized through demand side management programs and time of use metering. However, access to lower than retail electricity rates is imperative for economic hydrogen production. Partnership with a utility, or provision of benefits to a utility may be necessary to achieve the desired direct access contracts and supplemental grid electricity rates.

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Education

University of California, Davis: Institute of Transportation Studies, working towards an M.S. in Transportation Technology and Policy. Graduation Date: June 2005. Current G.P.A.: 3.6, Focus: Renewable Energy for Hydrogen Production in California

Undergraduate Studies: **California Polytechnic State University, San Luis Obispo**. Major: Mechanical Engineering, Focus: Renewable Energy for Power Production and Hybrid Vehicle Design. G.P.A.: 3.1, Recognition: Outstanding Contributions to the Public Image of the College of Engineering – Mechanical Engineering Department, Extraordinary Commitment as a Member of Mechanical Engineering Student Council

Experience

Associate Mechanical Engineer: Sacramento Municipal Utility District
7/02 – Present

Performance monitoring and database development for 900 system 10 MW PV fleet. Data Acquisition setup and operation for various systems. New PV mounting system design and testing. PV maintenance procedure development. Microturbine performance testing of Capstone 30 and 60. Greenhouse Gas Inventory development and implementation under California Climate Action Registry and EIA 1605b. Participation in Power and Utility Protocol Workgroup for GhG Registry Development. Lead technical advisor for SMUD hydrogen refueling station project currently being designed by Air Products.

Projects

NHA Student Hydrogen Station Design Contest, Team Lead
1/04 – 3/04

Lead a team of 7 students in the development of a design proposal for a wind energy electrolytic hydrogen fueling station. Proposal included technical, economic, safety, environmental, and marketing sections. www.h2ower.com

Publications

Bartholomy, Obadiah "Utility Peak Shaving Benefits of Distributed Photovoltaic Generation" March 2004, ACORE Power-Gen Renewable Energy, Las Vegas, NV

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