Economy Topic Team Report

California 2010 Hydrogen Highway Network

January 5, 2005

The Economy Topic Team Report was a collaborative effort by many people, some of whom contributed focused sections or passages involving specialized areas of expertise. The participation of and contributions from individuals represent neither an endorsement of the Report and its findings or recommendations, nor a verification of a review of the Report, by the individuals or the organizations they represent.

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Executive Summary

In April of 2004, California's Governor formally initiated development of a Hydrogen Highway, whose purpose is to accelerate introduction of hydrogen-fueled vehicles, especially fuel cell vehicles. Under the leadership ot the Secretary of CalEPA, the program, now labeled the California Hydrogen Highway Network (CA H2 Net), has assembled a group of experts to steer the program (the Advisory Board) and empowered several teams to provide in-depth assessment and recommendations for bringing the CA H2 Net to fruition between now and 2010.

The Economy Team is one of the five teams that have worked on the plan. It was charged with estimating the costs of building the CA H2 Net, assessing the capital requirements, and investigating the options to finance it. The Team's deliberations on financing policy intentionally did not result in recommending a specific financing option. The Team, however, is fairly certain that a private-public partnership is inevitable, if commercialization of hydrogen fuel is to take hold by 2010 and be accelerated for the years beyond 2010.

The Team's mission evolved as,

> *The mission of the Economy Team is to identify the public and private benefits, and returns to society that support the implementation of the California Hydrogen Highway Plan, to assess capital requirements, operating costs, and return on investment for emerging technologies, to identify the major sources of capital for them, and to identify and explain ongoing public and private measures that will ultimately lead to a sustainable hydrogen fuel industry.*

The Economy Team has addressed several topics:

- Estimating, with the help of the Blueprint Team, the Integration Team, and various outside experts, the cost of various hydrogen station configurations now feasible for deployment.
- Identifying the number and mix of stations needed to provide fueling for various vehicle deployment scenarios,
- Summarizing the overall capital requirements to build and operate those station scenarios, and,
- Identifying potential funding options for meeting those costs.

Network Design and Cost

The Economy Team evaluated a number of fueling station scenarios, with the number of fueling stations to be built between now and 2010 determined primarily on the basis of the number of hydrogen-using vehicles assumed to be on the road in California in 2010. For light duty hydrogen vehicle populations in the 10-20,000 range, an appropriate number of stations would be in the 250 range, or slightly less than 3% of California's existing 10,000 filling stations.

The dollar cost per hydrogen fueling station can vary significantly, depending upon whether the station is designed to handle dozens of cars per day (perhaps a fleet or high congestion location) or merely 3-4 cars per day. While building a limited number of high capacity stations might result in the most capital efficient delivery network, such a configuration would satisfy fleet requirements but would not satisfy the needs of "retail" or individual vehicle owners who will need more convenient and therefore more distributed fueling facilities with inherently lower utilization during the initial years of the CA H2 Net. Accordingly, there could be a fairly wide range of costs of building the network depending upon design and location criteria.

The Economy Team, with input from the other Teams, evaluated the cost of three scenarios and concluded that the construction capital requirement for building out the CA H2 Net is between $15 and $145 million. The associated annual financing requirement of these stations (on a levelized basis) will be in the range of $2 to $15 million per year. Assuming that drivers will pay gasoline price equivalence for their hydrogen fuel, the net operating costs (e.g. net of revenues) will be an additional $4 to $19 million per year. "All-in" costs, representing the sum of levelized annual capital construction costs plus net operating costs, will be in the $5 to $34 million per year range.

Summary Capital and Operating Cost Financing Needs

Scenario	A	B	C
# of Stations	50	250	250
# of Vehicles – Light Duty	2,000	10,000	20,000
# of Vehicles – Heavy Duty	10	100	300
Capital Construction, MM$	14.7	144.9	144.9
Annual Capital Cost (MM$/yr, levelized)	1.5	14.9	14.9
Operating Costs Minus Revenues, MM$/yr	3.6	14.0	18.7
Total Annual Net Cost[a], MM$/yr	5.1	28.9	33.6

[a] Sum of Levelized Capital Construction Costs plus Net Operating Costs

Funding the California Hydrogen Highway Network between Now and 2010

There are only two sources of capital to meet the construction and operating cost needs of the CA H2 Net: (a) private financing or (b) public funding sources. Private capital will be invested by corporations in the CA H2 Net if competitive investment returns are seen as resulting from that investment. Public capital (taxpayer or other public subsidies) will be required for a portion of total financing to the extent that private investors are unwilling to provide the full capital requirements of the CA H2 Net.

Given the general tenor of California's economy and concerns regarding the existing level of taxpayer burden, the Economy Team began its deliberations with a focus on how to obtain funding from private sources. The team examined various market-based policies to attract the flow of private capital to the CA H2 Net, including such ideas as franchising and providing investment tax credits.

The Team developed a broad array of private and public financing "tools" to help identify the type of financing approaches that best fit the challenge of financing the CA H2 Net. In subjecting these tools for comment by various funding entities, including CalPERS, the view from financial markets became fairly clear: private financing will be difficult. More to the point, the view from various financial experts is that the expected pace of development for hydrogen vehicles and the associated hydrogen fuel revenue streams at fueling stations will be well below levels that are needed to attract sufficient private investment to construct and operate the CA H2 Net.

Nonetheless, the Economy Team understands and accepts the view of the Governor, the Cal EPA secretary and the Advisory Panel that we should make every effort to "push the envelope" to accelerate the transition from a depleting and polluting hydrocarbon-based transportation model toward a hydrogen and fuel cell economy. Secondary but important benefits of the program involve economic and job development, as well as public health. The Economy Team agreed that any benefits of the CA H2 Net over the next 5-10 years will be largely *public* rather than private in nature. The report of the Benefits Subteam, (Section 3), outlines potential benefits of the CA H2 Net. Some of these benefits--reducing pollution and reducing depletion--are public benefits that do not translate readily into private investment inducements today. We can argue whether or not this is a good thing, but the view from the financial markets is that the *private* gains associated with the CA H2 Net lie too far into the future, and are too uncertain, to attract purely private financing. Public financing intervention will be essential for building a strong and viable CA H2 Net.

Bold Ideas for Important Benefits

The challenge for the Economy Team boiled down to investigating potential mechanisms and sources of capital to fund the first critical stages of a new fueling infrastructure that will enable fuel cell and hydrogen vehicle evolution to proceed at the fastest practicable pace. Everyone understands the "chicken and egg" nature of the challenge confronting fuel cell vehicle deployment. Until there is a hydrogen infrastructure, automotive fuel cell developers will not take the pace of fuel cell development to the highest possible level. But without fuel cell vehicles, there is little private incentive to build the fueling infrastructure. It is the role of public policy and political leadership to solve this issue.

The ideal policy trajectory for transitioning from fossil fuel transportation to hydrogen fueled transportation is one that is sparked by public support but which gives way to sustainable private market forces. The goal of the Economy Team was to identify sufficiently powerful measures that can be adopted today to get the industry to "critical mass" on the fastest realistic path. Several bold measures are seen as providing a mix of public and private financing impetus for advancing that goal.

Our team presents these bold ideas as just that: IDEAS. They are not formal recommendations. The make-up of the Economy Team was diverse enough that every bold idea had opponents. Rather than weed out our thinking to a few platitudes with no real punch, we chose instead to put forth ideas that will almost surely generate strong debate. In keeping with the spirit of open debate, our Report presents several dozen ideas with Pros and Cons. Among our ideas:

- Issue State of California bonds, possibly revenue bonds backed by:
  - A 1/4 cent (.025 cent) per gallon gasoline tax increase, or,
  - An equivalent carbon tax on all hydrocarbons consumed in the State,
  - Other revenue sources (e.g. emissions fees on existing cars or a general sales tax increase).
- Mandates on existing transportation fuel suppliers to have hydrogen fueling capability at 3% of their facilities by 2010.
- Encourage "dual use" energy applications for hydrogen stations such that stored hydrogen can be used to generate valuable on-peak electric power as well as to fuel vehicles.
  - Provide incentives and/or mandates for utilities to participate in the program.
- Provide tax credits for companies making qualified investments in the CA H2 Net.
- Require that a growing proportion of new state-operated vehicles and, later, private vehicle fleets (including rental car fleets), be hydrogen-fueled.

These ideas are not mutually exclusive. In fact, a combination of private and public initiatives is probably the best way to assure that all affected parties become engaged in the program.

Once again, California finds itself in a unique position to shape world thinking and action. The Governor and his leaders are committed to charting the transition of the transportation sector away from depleting and polluting hydrocarbons to a sustainable energy future built upon hydrogen and renewable technologies. This is an ambitious effort, but one driven by a sense that the status quo is non-sustainable, and that technologies are ripe enough for leadership to push the envelope now.

The CA H2 Net is being watched by energy experts everywhere. Most everyone agrees that hydrogen vehicles are the transportation "end game", but it is a huge challenge to disrupt existing fueling and automobile infrastructures.   It will take exceptional leadership. At the risk of sounding over dramatic, success with this initiative really could change the world. There may be no better place to take the first bold steps than here in California.

1. California Hydrogen Highway Network Costs

1.1 Introduction

California's leadership is committed to accelerating the commercialization of hydrogen and fuel cell vehicles to facilitate the State's transition to a clean transportation and energy future. The Governor has requested a California Hydrogen Economy Blueprint Plan, including a network of hydrogen fueling stations. A hydrogen fueling infrastructure is expected to help accelerate the commercialization of hydrogen-powered transportation services.

Creating a hydrogen fueling infrastructure is a challenge that must be met in order for hydrogen-powered transportation services to achieve commercialization. However, while a hydrogen fueling infrastructure is necessary for commercialization, it is not sufficient, by itself, to ensure sustainable commercialization.

For hydrogen-fueled transportation services to succeed commercially, they must be offered at prices comparable to competing transportation services. Hydrogen-powered transportation is technologically feasible today, but the cost of supplying such services currently exceeds the cost of conventional transportation services. To compete successfully and sustainably in the market for transportation services, therefore, the costs of supplying both fuel-quality hydrogen and hydrogen vehicles must be comparable to the costs of conventional fuel and vehicles.

The gulf that now exists in the market for transportation services between hydrogen-based and conventional transportation can be closed by either reducing the cost of hydrogen-based transportation, or by increasing the cost of conventional transportation services, or both.

As fossil fuel supplies become less available, and their impact on our environment becomes more visible, the price of supplying conventional transportation services is expected to rise. Meanwhile, technological innovation and practical experience are expected to reduce the cost of supplying hydrogen fuel and vehicles.

The California Hydrogen Highway Network (CA H2 Net) is expected to accelerate hydrogen fuel and vehicle cost reductions achievable through innovation and experience. Creating a network of hydrogen fueling stations will help attract the innovation resources needed to meet the many technological challenges. At the same time, a hydrogen fueling network creates a strategic opportunity to generate the practical experience needed to drive supply costs down the experience curve. Creating a hydrogen fueling infrastructure is only one step in the long march towards commercialization.

The Economy Topic Team expects California's hydrogen fueling infrastructure to help ensure California's leadership role in developing the technology, and in accumulating the experience needed to lower the cost of clean, sustainable hydrogen-based transportation services.

In the longer run, capital invested in the CA H2 Net may yield both private and public benefits, insofar as it accelerates the commercialization of hydrogen-based transportation services. However, the Economy Topic Team does not expect hydrogen-fueled transportation services to be commercially self-sustaining in 2010, the date specified in the Hydrogen Highway Blueprint Plan. We expect a hydrogen fueling infrastructure to produce significant social and environmental benefits when it is fully developed and commercialized, which we expect to occur much later than 2010.

1.2 California Hydrogen Highway Network Station Costs

Estimating costs of building hydrogen fuel stations in the future poses a real challenge. The fueling technology is in a research and development stage and improving. Cost estimates based on current data and information may mislead the potential future market that could develop to compete with other fuels. Complicating the estimation process is the difficulty of predicting the demand for hydrogen fuel in five, 10, or more years from now. To manage the complexities of the hydrogen station, the Economy Topic Team developed a cost model and used scenarios to calculate the capital and operating costs that would have to be incurred to accelerate the future commercialization of the hydrogen fuel in the transportation sector.

1.2.1 Summary of Cost Estimates

The purpose of this cost analysis is to (1) predict realistic near-term hydrogen station costs, and (2) identify important factors that affect station cost and quantify their effect. To achieve this, a Hydrogen Fueling Station Cost Model was developed to analyze the costs of stations according to three station mix scenarios, shown in Table 1. The stations listed in the table deliver 10, 30, 100, or 1,000 kg of fuel per day. To put this in perspective, a hydrogen fueling station that delivers 100 kg of hydrogen per day delivers enough energy to fuel about five gasoline SUVs.

The model calculates hydrogen station costs for various technologies and capacities. Figure 1 shows the results for the three scenarios. The annualized cost for Scenario A is about \$6 million, for Scenario B about \$37 million. and for Scenario C \$43 million. Assuming hydrogen can be sold at the stations for \$3 per kilogram, the net annualized costs would amount to \$5 million for Scenario A, \$29 million for Scenario B, and \$29 million for Scenario C.

Table 1. Station Type, Rated Capacity, and Station Mix Scenarios

Station Type	Capacity (kg/day)	Station Mix Scenarios		
		A	B	C
1 Steam methane reformer	100	12%	8%	8%
2. Steam methane reformer	1,000	0%	1%	1%
3. Electrolyzer, grid electricity	30	6%	6%	6%
4. Electrolyzer, some photo-voltaic electricity	30	18%	28%	28%
5. Electrolyzer, grid electricity	100	10%	8%	8%
6. Mobile refueler	10	20%	28%	28%
7. Delivered liquid hydrogen	1,000	8%	3%	3%
8. PEM/Reformer energy station	100	18%	14%	14%
9. High-temp. fuel cell energy station	91	Combined with 8	Combined with 8	Combined with 8
10. Pipeline hydrogen station	100	8%	4%	4%
Number of Stations		50	250	250

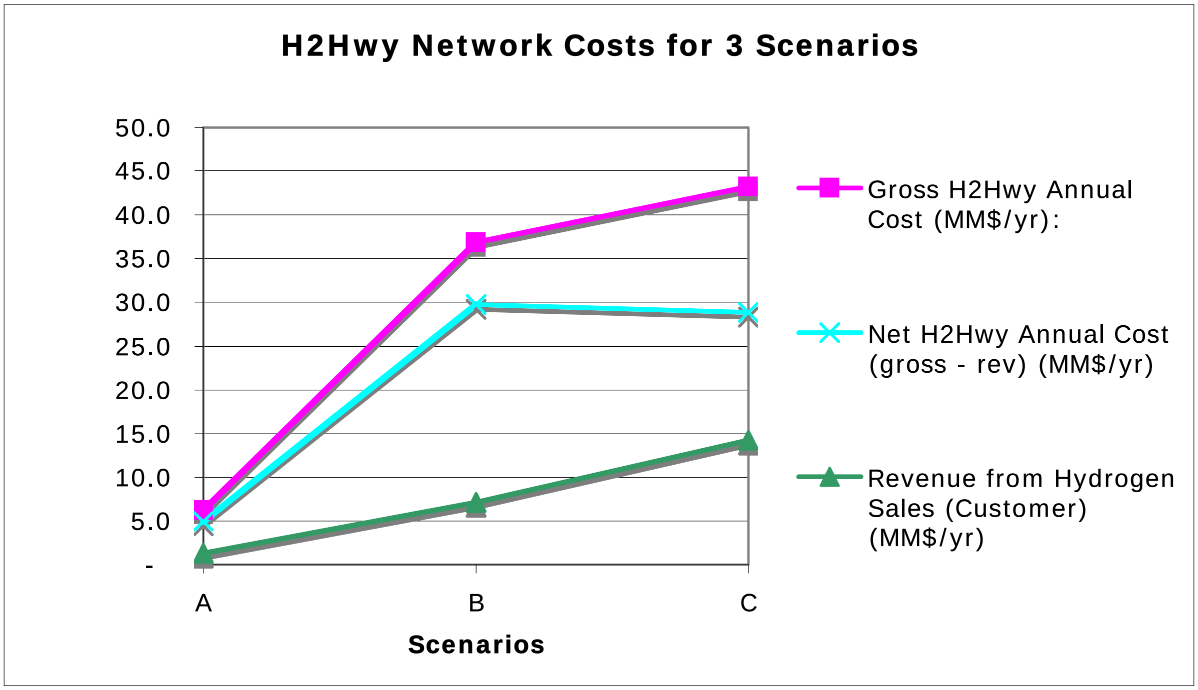

Figure 1. Hydrogen Station Costs for Scenarios A, B, and C

The cost items in the model are sensitive to several factors. Location of the station, input fuel to produce hydrogen, and capacity utilization are examples of the factors that can influence the station costs. To put a range or a bound around the estimates presented in Figure 1, the model assumptions were changed based on two additional sets of siting assumptions that are labeled, in Table 2, "Fleet Location," to represent a case where the vehicles demanding hydrogen are clustered in an area, and "Champion Application," to represent an ideal set of assumptions that facilitate building and operating the stations with cost reduction in mind. Table 2 shows the cost and other assumptions used for the three scenarios and the new assumptions. Figure 2 shows the results of the cost estimates.

Table 2. Input Data for Hydrogen Station Cost Estimates

Parameter	Scenarios A, B, and C	Fleet Location	Champion Applications
Natural gas ($/MMBtu)	$7.00	$6.00	$5.00
Electricity ($/kWh)	$0.10	$0.06	$0.05
Demand charge ($/kW/mth)	$13	$13	$13
Capacity Factor (scen. A, B, C)	16%, 24%, 47%	16%, 24%, 47%	16%, 24%, 47%
After-tax rate of return	10%	8%	6%
recovery period in years	15	15	15
% of labor allocated to fuel sales	50%	30%	20%
Real Estate Cost ($/ft^2/month)	$0.50	$0.50	$0
Contingency	20%	15%	10%
Property Tax	1%	1%	1%

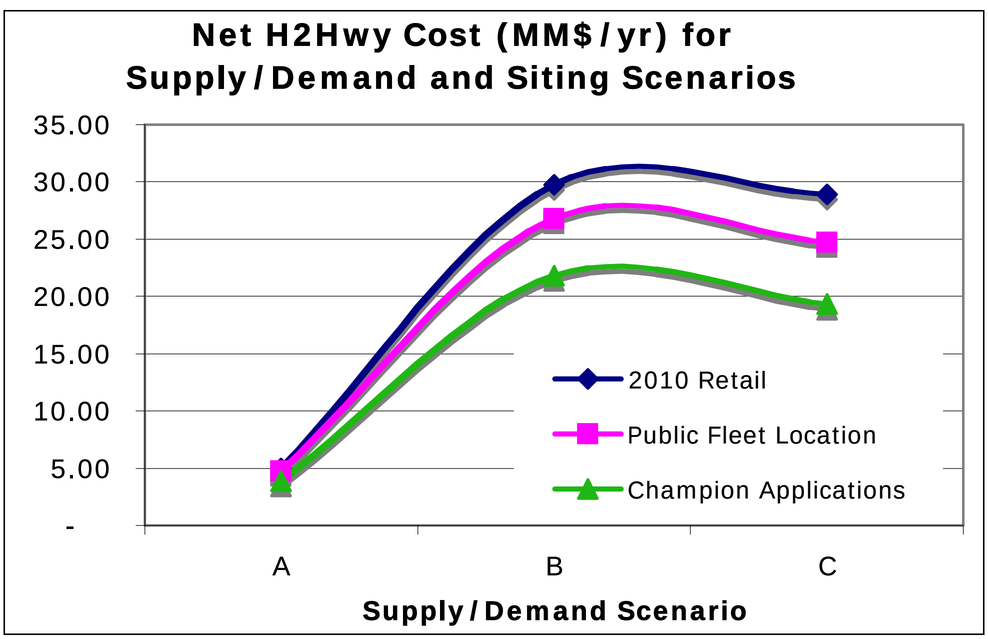

Figure 2. Cost Estimate Results

The "Fleet Location" case lowers the costs somewhat, but the "Champion Application" case lowers the costs much more. Scenario A under the "Champion Application" costs about $3 million, Scenario B about $22 million, and Scenario C about $19 million. The scenarios and the analyses are more fully explained in the remainder of this Topic Team Report.

1.2.2 Hydrogen Fueling Station Cost Model

The CA H2 Net hydrogen fueling station cost model is an Excel spreadsheet program that calculates station costs using assumptions and data for ten different types of stations. Table 3 shows the station types and their rated capacities.

Table 4 shows the equipment used in each of these stations. “Key Technology” describes the equipment used for hydrogen production or delivery. The “Additional Components” are used to compress, store and dispense the hydrogen into vehicles.

Table 3. Station Types and Capacities Analyzed by the Hydrogen Station Cost Model

Station Type	Capacity (kg/day)
1. Steam methane reformer	100
2. Steam methane reformer	1,000
3. Electrolyzer, grid electricity	30
4. Electrolyzer, some photo-voltaic electricity	30
5. Electrolyzer, grid electricity	100
6. Mobile refueler	10
7. Delivered liquid hydrogen	1,000
8. PEM/Reformer energy station	100
9. High-temp. fuel cell energy station	91
10. Pipeline hydrogen station	100

Table 4. Station Equipment

<table>
<tr><th>Station Type</th><th>Key Technology</th><th>Additional Components</th></tr>
<tr><td>Mobile Refueler</td><td>Integrated Refueler Trailer</td><td>Cascade storage/dispensing</td></tr>
<tr><td>Natural Gas Reformer</td><td>Steam Methane Reformer, Pressure Swing Absorption</td><td rowspan="2">Reciprocating-piston compressor,
cascade storage/dispensing</td></tr>
<tr><td>Electrolyzer</td><td>Alkaline Electrolyzer</td></tr>
<tr><td>Delivered LH_2 Tanker Truck</td><td>Cryogenic Storage Tank, 6,250 Cryo-pump</td><td>evaporator + cascade storage dispensing</td></tr>
</table>

1.2.2.1 Specialty Stations

In addition to the seven stations listed above in Tables 1 and 3, the model examines the cost of three other types of "specialty stations." These are stations that have a unique characteristic that makes them more economical under special circumstances. The specialty stations being considered include:

Energy Station

This type combines on-site hydrogen fuel production with electricity production using a fuel cell. This configuration yields three sources of revenue: hydrogen fuel, electricity, and heating/cooling. An energy station is best sited at a facility with large or premium (uninterruptible) electricity loads, such as a hospital, or manufacturing facilities with a steady demand for industrial hydrogen.

Because of the complex relationship between the price of electricity, the price of hydrogen, and how the station is operated, we made some simplified assumptions for the energy station. We assume the fuel cell provides some peak-shaving capability and runs whenever available hydrogen is not required for vehicle fueling. The model assumes the reformer runs at 100% capacity and that any hydrogen not sold to vehicles is converted into electricity for the building. The fuel cell is sized to be able to process all excess hydrogen from the reformer when vehicle capacity factor is at its lowest. In this case, at 16% vehicle capacity factor and 90% fuel cell capacity factor, the 100 kg/day reformer requires a 64 kW fuel cell. We assume the electricity produced by the fuel cell sells at a 25% premium ($0.125/kWh vs. $.1/kWh) since it will be used for demand reduction and emergency back-up. Even at the highest vehicle capacity factor (47%), there will be ample hydrogen available for electricity demand reduction (peak-shaving)

Operating cost for the PEM/Reformer energy stations is determined by subtracting the electricity revenue from the operating costs. This figure is added to the levelized capital cost for all the equipment (including the PEM fuel cell and electronics) to determine the total annual station cost. The cost of hydrogen is calculated by dividing this total annual station cost by the amount of hydrogen produced for vehicles.

The high-temperature fuel cell energy station assumption does not take vehicle capacity factor into account. It produces the same amount of hydrogen regardless of capacity factor. Also, the cost of the fuel cell for these high-temp and PEM energy stations assume a $2500 and $1500/kW subsidy, respectively, from the California Public Utilities Commission (CPUC).

Pipeline Stations

Stations built near an existing hydrogen pipeline have the advantage of a reliable low-cost source of hydrogen and eliminates the need for on-site production and delivery. A hydrogen pipeline runs between Torrance and Long Beach, offering the opportunity to site several stations along this line.

Biomass Gasification

Hydrogen can be produced from local community green waste (e.g. pine needles, stumps, lumber, wood waste) using biomass gasifiers. Since the biomass feedstock is typically a wastestream, the feedstock for this hydrogen source is both economical and renewable.

It is assumed the costs for this option are similar to the costs of a liquid hydrogen or mobile refueler station since the only difference between them is the source of the delivered hydrogen. Stations located near these biomass gasification plants could receive biomass-based liquid hydrogen. Representatives from this industry[1] claim a lower delivered liquid hydrogen cost than what is currently achieved at large-scale hydrogen production plants using natural gas, however, we assume they will sell this hydrogen to industrial gas suppliers for the market value.

1.2.3 Methodology

Station costs are calculated by determining the size and type of equipment needed for a given station, estimating this equipment's cost using data from industry, and estimating how much it will cost to install and operate this equipment. The following steps were taken for the cost calculations.

1. Industry Contacted for Cost Data

Suppliers of hydrogen equipment provided data on the capital, installation, and operating costs of their equipment (see Appendix E for these data and Appendix F for the list of companies that contributed information). Costs for additional station components (e.g., safety equipment, mechanical/piping) were provided by TIAX LLC, a consulting company.

2. Cost Data Adjusted for Size and Production Volume

In this step, cost data for units of different size and production volumes are normalized and aggregated. Because the costs collected from industry represented a wide variety of sizes and production volumes, the data was scaled to a uniform size and production volume level based on assumed scaling factors and progress ratios. Since there was a larger amount of data available on storage and compressors, these costs are determined from a regression of the equipment costs vs. size data. Dispensers cost data, since independent of size, are simply averaged.

Scale Adjustment: The data collected from industry were scaled to a uniform size based on the ten station sizes selected. For example, the reformers were scaled to 4.17 and 41.7 kg/hr to correspond to the 100 kg/day and 1,000 kg/day station sizes. The formula used to scale each industry cost estimate is:

[1] Grand Teton Energy, personal communication, Oct. 2004.

$$Cost_f = Cost_i \times \frac{Size_f}{Size_i}^{ScalingFactor}$$

Where “f” designates the size and cost of the scaled equipment, and “i” designates the original estimate. Using the above formula, the calculated scaling factor for reformers is 0.60, electrolyzers 0.44, purifiers 0.50, and fuel cells 0.70.

Scaling factors for storage and compressors are derived based on curve-fitting the data. Appendix E shows the results of the scaling adjustment for production and purification equipment.

Production Volume Adjustment: To calculate cost reduction from production volume increase, progress ratios are estimated for the equipment. The equipment is clustered into three categories to reflect its maturity (as of 2004) and potential for cost reduction. Each cluster has an associated progress ratio. The Table 5 shows the clusters categories and their assumed progress ratios.

Table 5. Production Volume and Progress Ratios

Cluster	Equipment	Progress Ratio
1. Nascent Technology, Low production volume (1-10yr)	Reformers, electrolyzers, purifiers, fuel cells	0.85
2. Mature equipment, predominantly used for H2 stations	Compressor, dispenser, mobile refueler, non-capital station construction costs	0.90
3. Mature equipment, high production volume	Storage	0.95

Different progress ratios were selected since the equipment in each cluster are at different levels of maturity and production volume today. For instance, an increase in ASME storage vessel production will have a negligible effect on price since they are already produced in volume and have been so for many years. Alternatively, only a limited amount of small scale reformers have yet been built, thus there is a higher potential for cost reduction with this equipment. The progress ratios take these differences into consideration.

Equipment cost estimates are based on cumulative production volume levels. To calculate future cumulative production volume levels, we assumed a current production volume for each piece then added the number of units required based on the station mix and station number. For instance, Scenario C calls for 250 stations, 20 of which are small reformers. Thus, 2010 production volume level adds 20 to the current assumed production volume (3 units) of reformers. This method does not account for production volume increases due to non-CA H2 Net stations.

Since the stations will presumably be built over 5 years (2005-2010), we use the average cost of the equipment over the 5 years taking into account the continual reduction in cost due to production volume increase. This is done using the following equation:

$$R = \frac{P_f}{P_i}$$

$$\alpha = \ln(R)/\ln(2)$$

$$DF = \left(\frac{1}{1+\alpha}\right)\frac{(R^{(\alpha+1)}-1)}{R-1}$$

$$C_f = C_i \times DF$$

Table 6 shows the production volume assumptions and calculated discount factors for each piece of equipment using the Scenario C station mix and number.

Figure 3 shows how the costs for various pieces of equipment change for different scenarios.

Table 6. Production Volume for Hydrogen Station Equipment

Equipment	Type	Current Cumm. Prod. Vol. (units)	2010 Projected Prod Vol. (units)	Learning Factors	Prod. Vol. Discount Factor
Reformer	SMR, Pressurized, 10 atm	4	24	0.85	0.77
Electrolyzer	Alkaline	10	116	0.85	0.68
Purifier	Pressure Swing Absorption	10	79	0.85	0.73
Compressor	Reciprocating	100	282	0.90	0.91
Storage	6,250 psi carbon steel tanks, cascade system, avg. vessel size 1.5 m^3	300	949	0.95	0.95
Dispenser	Cafcp protocol	17	217	0.90	0.77
Fuel Cell	PEM/MCFC	5	32	0.85	0.76
Mobile Refueler	includes storage, compressor, and dispenser	10	78	0.90	0.82
LH_2 Equipment	Includes Dewar and Vaporizer	5	12	0.90	0.93
Station Construction (non-capital Costs)		15	265	0.9	0.74

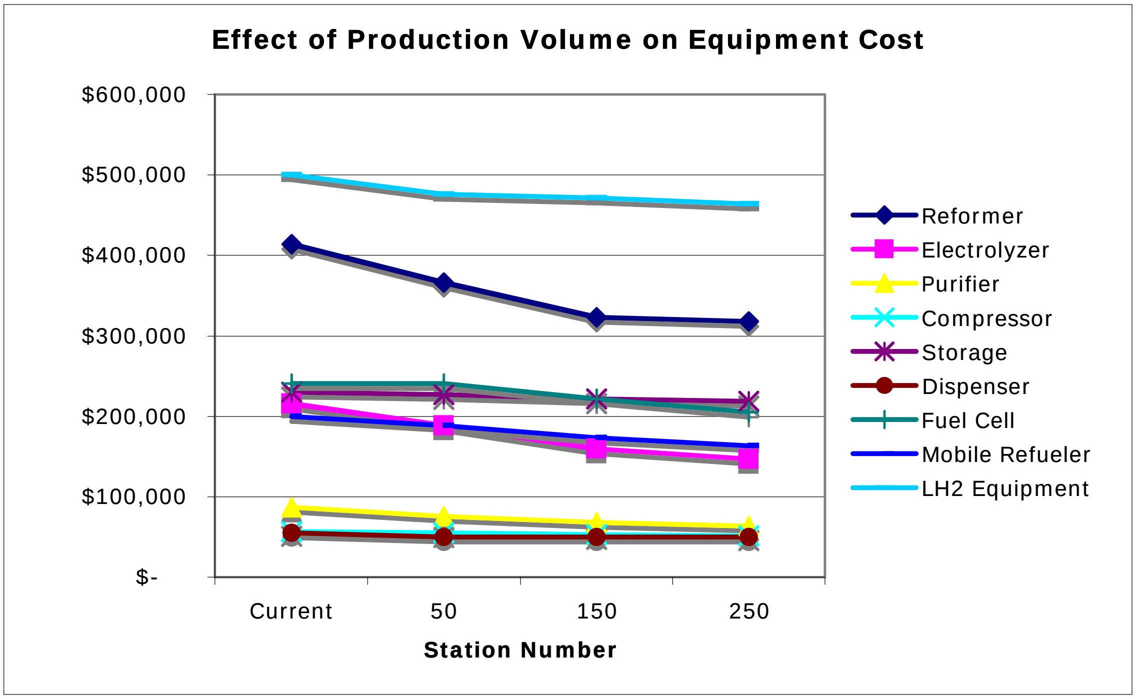

Figure 3. Effect of Production Volume on Equipment Cost

3. Application of Adjusted Costs in Model

Once the aggregated price for each piece of equipment is calculated, it is then used in the model. Appendix E shows the aggregated, scaled equipment costs used in the model.

4. Assumption Validation

The assumptions used in this model (see Appendix C) were vetted by the Economy Topic Team and TIAX. They were also compared against the assumptions used in other reports such as National Academy of Sciences, TIAX, GM Well to Wheels Study. An example of this comparison is provided in Table 7.

5. Model Validation

To ensure the model uses the cost and assumptions accurately, the model has undergone peer review within the Economy Topic Team. TIAX also compared the model against the Hydrogen Analysis (H2A) Topic Team's economic model of forecourt station economics. The team is in the process of setting up a formal peer review committee made up of economic modelers and hydrogen experts.

Table 7. Peer Review Comparisons of Data Used in the Cost Model

Parameter	Study	On-site NG Reformation	Electrolysis
Total Electric Consumption (kWh/kg)	***H2Hwy 2010***	3.0	60
	Lasher/ADL	3.41	53.45
	GM/LBST	2.16	53.84
	Simbeck/SFA Pacific	2.19	54.8
Natural Gas Consumption (J/J)	***H2Hwy 2010***	1.35	—
	Lasher/ADL	1.32	—
	Simbeck/SFA Pacific	1.43	—

1.2.4 Data and Assumptions

Table 8 presents the key assumptions used in the model. These are the assumptions that get modified when conducting sensitivity and scenario analyses.

Table 8. Key Model Variables

Natural Gas Price ($/MMBtu)	7
Electricity Price ($/kWh)	0.1
Capacity Factor (%)	70%
Equipment Life	15 yrs
Return on Investment	10%
% of labor allocated to fuel sales	50%
Real Estate Cost ($/ft^2/month)	0.5
Contingency (% of total capital cost)	10%

Capacity Factor: involves rated capacity and the delivery of hydrogen. The rated capacity or output for a hydrogen station reflects the amount of fuel that can be delivered during a fueling window. The fueling window typically consists of two periods of peak activity during the day or about 10 total hours of busy operation. The cost analysis performed by the team takes into account the number of dispensers as well as the hydrogen storage needed to provide fuel during the fueling window. In the case of on-site reformer or electrolyzer systems, the storage capacity was designed to accommodate one day of operation. The storage capacity is sufficiently large to enable cascade filling of all of the vehicles and store hydrogen produced at night. In the case of delivered hydrogen (LH_2, compressed, or pipeline), the compressor capacity is larger and the storage capacity is smaller than that of an on-site production station. Therefore, the hydrogen delivery capacity for these stations would be much larger (about 2.4 times) if based on a 24-hour operating window. However, in order to be consistent with the definition of rated capacity, the designation for the delivered hydrogen stations also reflects the amount of fuel that can be dispensed during a 10 hour fueling window.

Equipment Life: denotes the useful life of the equipment. We assume that at the end of *N* years, the equipment has no salvage value. *N* is also the recovery period of the investment.

Return on Investment: is the assumed interest rate on the borrowed capital for installation and equipment. It takes into account the opportunity cost of the borrowed capital. It does not mean that the proposed projects at the current market conditions will return a profit. Return on Investment (ROI) and Equipment Life is used to calculate the capital recovery factor (or “fixed charge rate”). The formula for calculating this is:

$$CRF = \frac{ROI}{1-(1+ROI)^{-N}}$$

Real Estate Cost: accounts for the cost to rent the land the station equipment occupies.

Contingency: includes unexpected costs that arise during the station construction process. Contingency is typically a function of capital cost and is therefore represented in the model as a percentage of total capital equipment costs.

Equipment Sizing: The compressor and storage equipment is sized to be able to fuel 40% of the daily expected vehicle load in 2 hours. For stations with on-site generation, the compressor size must match the production equipment capacity since there is no storage buffer between these two systems. The storage system must be large enough to store hydrogen generated throughout the night and serve the daily vehicle demand. For stations with delivered hydrogen, there is more flexibility in choosing compressor size, however there is a trade-off between compressor and storage size. Using a larger compressor allows for smaller storage and vice-versa. See Appendix G: “Compressor and Storage Sizing” for the details on these calculations. Table 9 shows the compressor and storage size for each station type.

Site Assumptions: The model assumes small and large H_2 stations are integrated into existing gasoline stations with 8 dispensers total. Small station use one cH_2 dispenser and large station use three cH_2 dispensers. Figure 4 provides an example of LH_2/gasoline station layout.

Design Assumptions: The stations store hydrogen at 6,250 psi to serve fuel vehicles with 5,000 psi on-board vehicle storage. The storage and compression equipment is sized to deliver 40% of the station’s daily throughput in two hours. It does not take into account capacity factor.

Table 9. Compressor and Storage Sizes for the Stations

Station	Storage (kg)	Compressor Size (kg/hr)
1. Steam methane reformer	149	4.2
2. Steam methane reformer	1493	41.7
3. Electrolyzer, grid electricity	43	1.3
4. Electrolyzer, some photo-voltaic electricity	43	1.3
5. Electrolyzer, grid electricity	144	4.2
6. Mobile refueler	75	Not applicable
7. Delivered liquid hydrogen	667	666.7
8. PEM/Reformer energy station	32	31.5
9. High-temp. fuel cell energy station	96	96.3
10. Pipeline hydrogen station	35	35.0

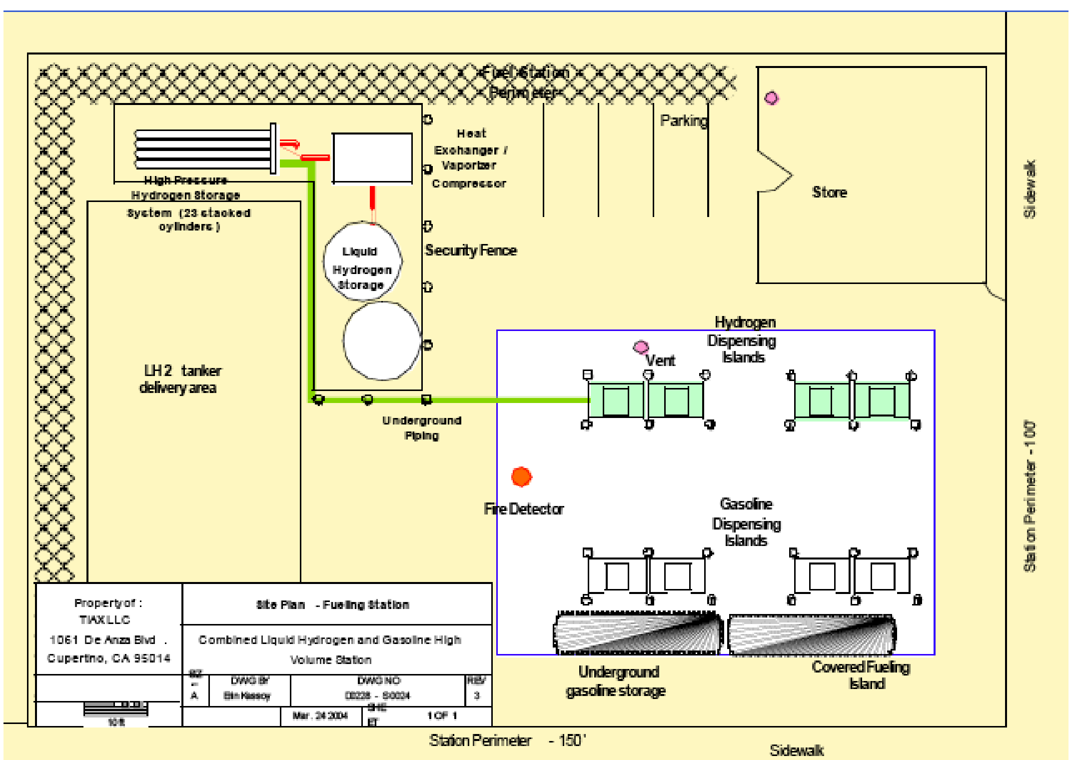

Diagram provided by TIAX, LLC

Figure 4. Example Layout of LH_2/Gasoline Station

The 30 kg/day electrolysis station is the only station to use renewable electricity to produce some of its hydrogen. For this station, we assume the photo-voltaics cost $\$3/W_{peak}$, and the solar array is sized to provide ~17% of the total electricity to make hydrogen when the station operates at 50% capacity.

Economic Assumptions: Station labor costs are divided between hydrogen, gasoline, and non-fuel sales using a factor of 1/8 or 3/8 (depending on small or large station). Rent costs for both station landscape and hardscape are calculated based on an assumed rent rate and station area (based on the site plan).

When calculating the levelized cost of the station ($/yr), the capital cost of the station is amortized over 15 years with 10% return ROI based on a 15 year plant life (n). This yields a fixed charge rate (or capital recovery factor) based on the following formula:

$$FCR = \frac{ROI}{(1-(1+ROI)^{-n})}$$

Energy Prices: The energy prices used in the model are based on a review of several published commercial utility rates. Electricity prices range from $0.097/kWh (California Energy Commission [CEC]), to $0.124/kWh (Chevron Texaco), to $0.04/kWh (City of San Francisco). Natural gas prices range from $6.68/MMBtu (Department of Energy EIA) to $5.93/MMBtu (Wall Street Journal, August 2004).

1.2.5 Supply and Demand Scenarios

The three scenarios developed by the CA H2 Net teams reflect different levels of hydrogen supply and demand in terms of number of stations and number of light duty, and heavy duty hydrogen vehicles, and the station types that are likely to be built. Other governmental efforts have lead to building hydrogen stations. Currently, several hydrogen stations are either already built and operating, or in the design stage to be built. It is anticipated that these efforts would amount to about 50 hydrogen fueling stations in California. Scenario A is very close to the existing and planned stations and is considered the base scenario or the conditions in 2010. Scenarios B and C project 250 stations to be built which represent the scenario of providing increased hydrogen accessibility to the general public. Scenarios B and C differ in their capacity utilization rates reflecting increased hydrogen demand by increasing number of hydrogen vehicles. The process for selecting station mixes is described in more detail in CA H2 Net Blueprint Report. Table 10 shows how many of each station is allocated to each scenario.

The Demand Scenarios A, B, and C correspond to the above supply scenarios of the same symbols. They are presented in Table 11. The demand scenarios vary in the number of vehicles. Scenario C assumes the highest demand, 10 times Scenario A, and twice as much as Scenario B. Notice that Scenarios B and C correspond to the same supply scenario of 250 stations, but Demand Scenario C is high enough to double the capacity utilization. The increases in the demand and the capacity utilization are not considered sufficient to put pressure on hydrogen prices to increase.

Table 10. Supply Scenarios: Station Type, Rated Capacity, and Station Mix Scenarios

Station Type	Capacity (kg/day)	Station Mix Scenarios		
		A	B	C
1. Steam methane reformer	100	12%	8%	8%
2. Steam methane reformer	1,000	0%	1%	1%
3. Electrolyzer, grid electricity	30	6%	6%	6%
4. Electrolyzer, some photo-voltaic electricity	30	18%	28%	28%
5. Electrolyzer, grid electricity	100	10%	8%	8%
6. Mobile refueler	10	20%	28%	28%
7. Delivered liquid hydrogen	1,000	8%	3%	3%
8. PEM/Reformer energy station	100	18%	14%	14%
9. High-temp. fuel cell energy station	91	Combined with 8	Combined with 8	Combined with 8
10. Pipeline hydrogen station	100	8%	4%	4%
Number of Stations		50	250	250
Capacity Utilization		16%	24%	47%
Total Hydrogen Produced/yr (kg/yr)		425,532	2,380,952	4,761,905

Table 11. Demand Scenarios: Number and Types of Vehicles

	A	B	C
Total # of Stations	50	250	250
Hydrogen Price to Customer ($/kg)	$3.0	$3.0	$3.0
Light-Duty Vehicles	2,000	10,000	20,000
Heavy-Duty Vehicles	10	100	300

1.2.6 Bounding Scenarios

In addition to running Scenarios A, B, and C, we have developed three siting scenarios under which to analyze station costs. They are labeled a “Base Case 2010 Retail Station,” “Fleet Location,” and “Champion Applications.” Combining the supply and demand scenarios with the siting scenarios yields an upper and lower bound on the CA H2 Net cost estimate for Scenarios A, B, and C. For each of the bounding scenarios, we assume Scenario B station number, station mix, and vehicle demand. Table 12 shows the assumptions under each siting scenario.

Table 12. Siting Scenario Assumptions

Parameter	Scenarios A, B, C	Fleet Location	Champion Applications
Natural gas ($/MMBtu)	$7.00	$6.00	$5.00
Electricity ($/kWh)	$0.10	$0.06	$0.05
Demand charge ($/kW/mth)	$13	$13	$13
Capacity Factor	16%,24%,47%	16%,24%,47%	16%,24%,47%
After-tax rate of return	10%	8%	6%
recovery period in years	15	15	15
% of labor allocated to fuel sales	50%	30%	20%
Real Estate Cost ($/ft^2/month)	$0.50	$0.50	$-
Contingency	20%	15%	10%
Property Tax	1%	1%	1%

The Fleet Location Scenario involves siting the station at a fleet vehicle site such as a bus yard or near a cluster of private or government vehicles. This will enable higher throughput and therefore higher capacity factors since the location ensure a steady reliable demand. This type of facility may also be able to achieve a lower utility rate through incentives and if it is able to qualify for industrial classification.

The Champion Application Scenario involves siting the station at “champion” facilities involving partners committed to the projects success in order to minimize expenses and maximize the capacity factor. Leveraging public-private partnerships may enable attractive financing schemes and facilitate stronger local authority cooperation with permitting. Co-locating the station at an existing industrial gas user or distributed generation application will raise capacity factor. Cost improvements resulting from the aforementioned factors will enable more stations to be built, thus creating higher equipment production volumes.

1.2.7 Hydrogen Highway Network Cost Estimates

This section presents the costs of individual stations and the cost of the overall CA H2 Net using current technology. It presents these costs for multiple scenarios. The assumptions used in each scenario are presented in Appendix C. Figure 5 presents the costs of Scenarios A, B, and C.

Table 13 presents the costs in more detail. The scenarios can be interpreted from a cost and hydrogen vehicle point of views as modest, moderate, and aggressive vehicle and station roll-out strategies. Figure 6 shows the annual cost of the network for the three scenarios. The assumptions for each scenario are provided in Table 1.

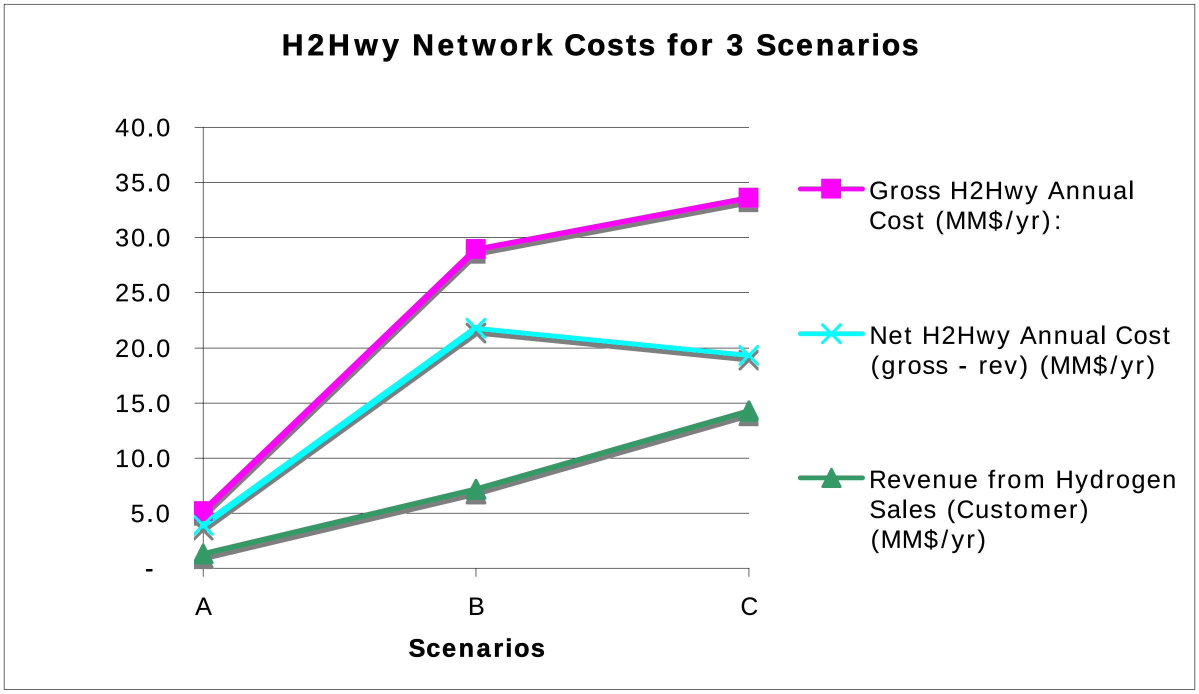

Figure 5. Costs of Scenarios A, B, and C

Table 13. Costs of Scenarios A, B, and C

Scenario	A	B	C
No. of Stations	50	250	250
No. of Vehicles	2,000	10,000	20,000
Gross Annual Cost	$ 5 - 6	$29 - 37	$34 - 43
Revenue	$1	$7	$14
Net Annual Cost	$4 - 5	$22 - 30	$25 - 35

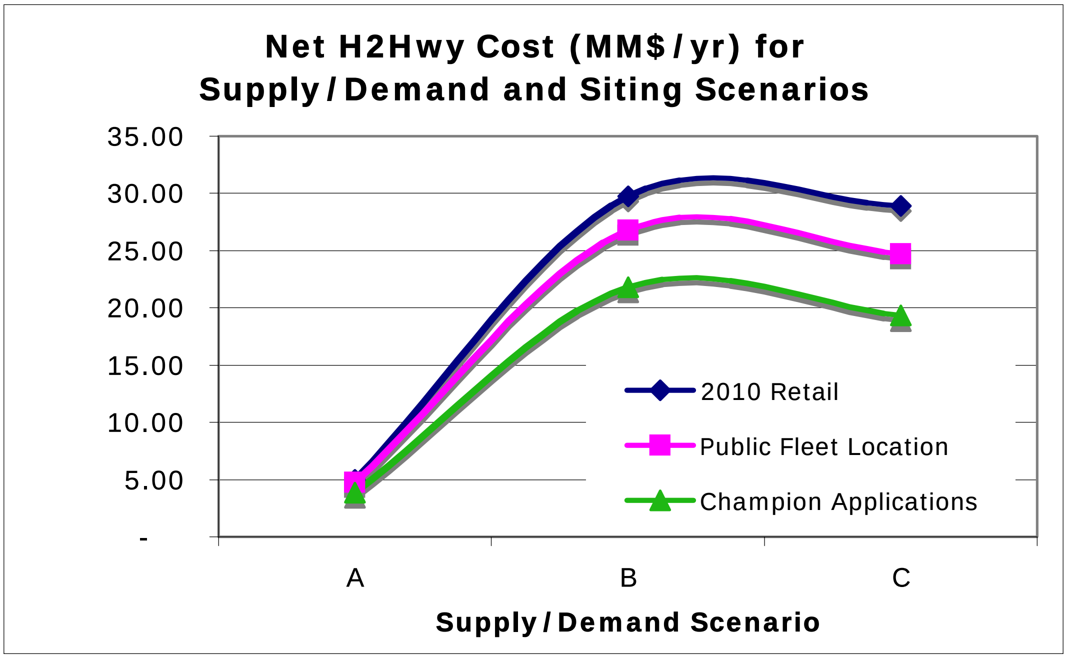

Figure 6. Annual CA H2 Net Costs for Scenarios A, B, and C

The gross annual cost expressed in millions of dollars per year represents the levelized annual costs to build and operate the CA H2 Net over 15 years. It covers the repayment of the initial investment to build stations and the annual operating costs. Normally, these costs would be covered by the revenues from the sale of the fuel. Because the market fuel prices are likely to dictate a price of $3 per kilogram of hydrogen, the annual cost may not be covered. The price of $3/kg once adjusted for about 60% more fuel efficiency is equivalent to about a $2.00 average price of gasoline.

The net annual cost is the cost that still would have to be covered by some other means. The net annual cost subtracts the revenue gained by selling hydrogen to customers at $3/kg from the gross cost.

The modified assumptions that comprised additional scenarios of "Fleet Location", and "Champion Applications" alter the costs. The costs of these bounding scenarios are presented in Figure 5.

A comparison of all scenarios reveal that costs could be reduced by aggressively accelerating access to capital, location, and capacity utilization. Figure 7 shows the capital recovery expense, operating costs, and the revenues from the sales under each of the main scenarios, A, B, and C, and the Bounding Scenarios of “Fleet Location,” and "Champion Application."

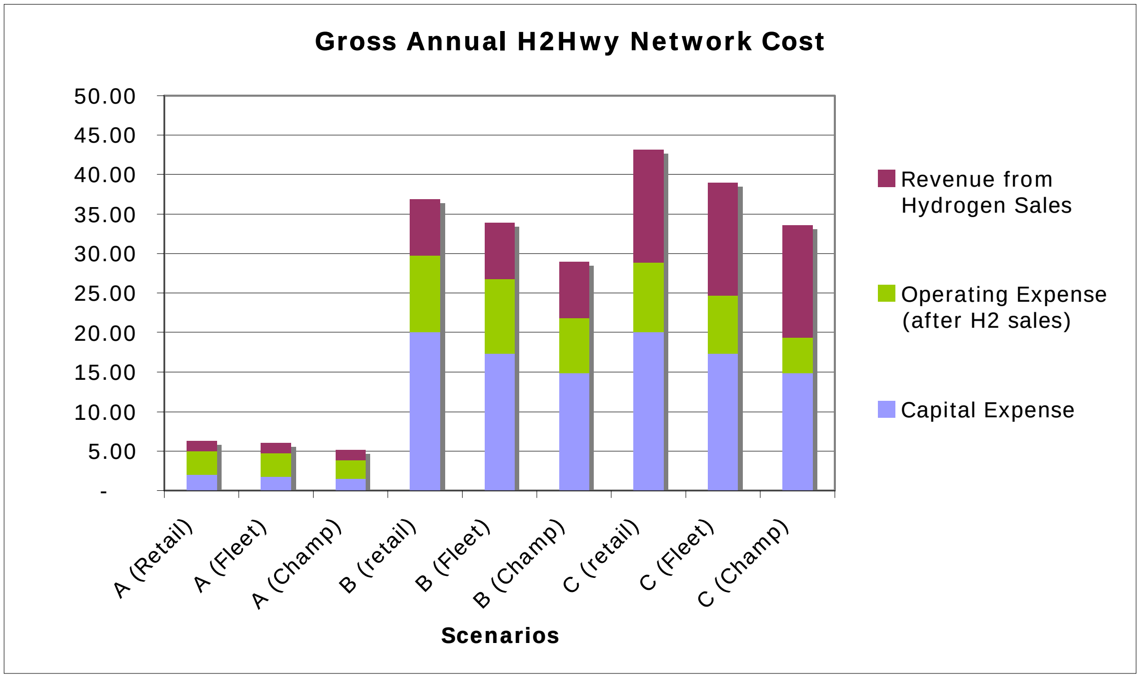

Figure 7. Gross Annual CA H2 Net Cost

1.2.8 Individual Station Type Costs

Station costs are divided into four main categories: financing, installed capital, fixed operating and feedstock. Capital includes the levelized equipment cost and one-time non-capital installation costs. Financing (i.e., fixed charge rate) includes the cost of borrowing the capital required to build the station assuming a certain return on the investment over N years (10% ROI and 15 years is the baseline assumption). Fixed Operating includes all recurring annual expenses at the station except feedstock costs. Feedstock includes the cost of fuel to the station (e.g. natural gas, electricity, gaseous hydrogen, liquid hydrogen). These costs are presented in Figure 8. Since annual station costs are very similar between Scenario A and C, only Scenario C is shown.

The top two bars in Figure 7 together represent the total levelized capital cost. The financing charge is:

$$FC = \left(CRF - \frac{1}{N} \right) * CapitalCost$$

It only applies to the capital invested. This does not imply the station operator makes a return on operating the station. If the return on investment is set at zero percent, the blue bar in the cost figures disappears.

To illustrate how these costs compare to gasoline and conventional vehicles on a cost per mile and per fill-up basis, Table 14 provides an example.

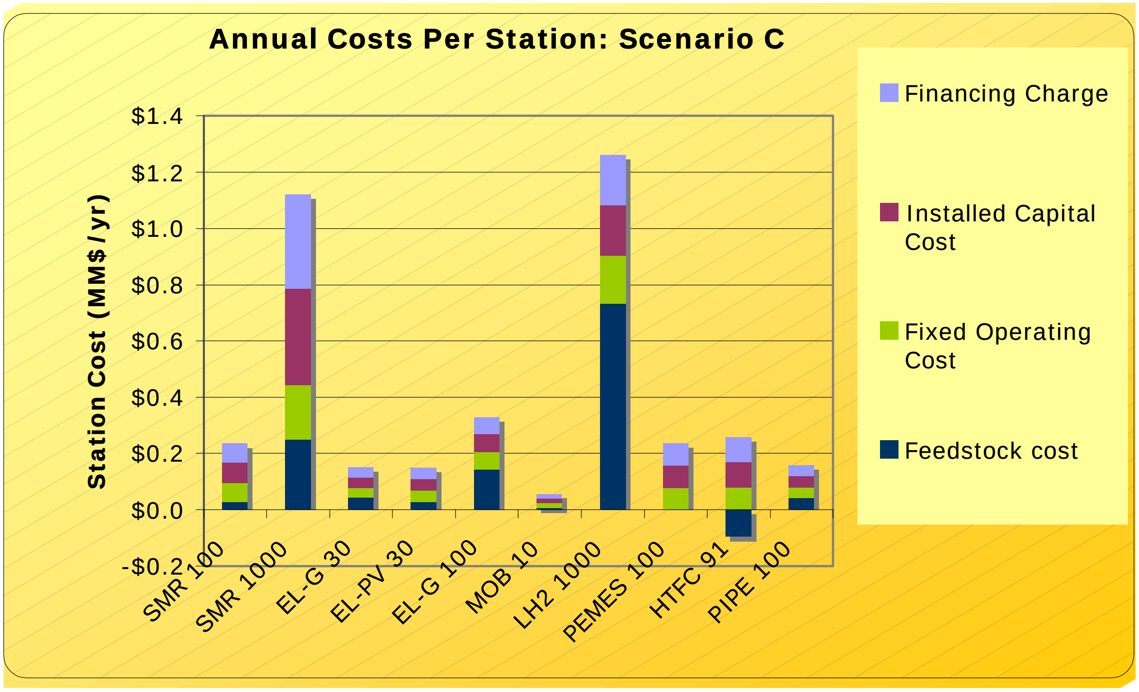

Figure 8. Annual Costs per Station for Scenario C

Table 14. Comparison of Hydrogen Costs to Gasoline Costs

Parameter	Hydrogen	Gasoline
Mpg (equiv.)	40	25
Fuel Cost ($/kg, $/gal)	$3.00	$2.30
Fuel Tank size (kg, gal)	4	12
Range (miles)	160	300
Cost Per Fill-up	$12.0	$27.6
Cost per mile	$0.075	$0.092

To illustrate what costs are considered for each individual station and the amount each item contributes to overall hydrogen price, Figure 9 is provided for a reformer-type station example. Station cost pie charts for the other stations considered in this analysis are included in Appendix A.

Fixed Operating Costs includes items like equipment maintenance, labor, rent, and insurance. Installation Costs includes non-capital costs of building the station such as engineering, permitting, construction, etc. Additional Equipment includes mechanical, electrical, and safety equipment. For a complete list of the costs for the SMR 100 station, see Appendix B.

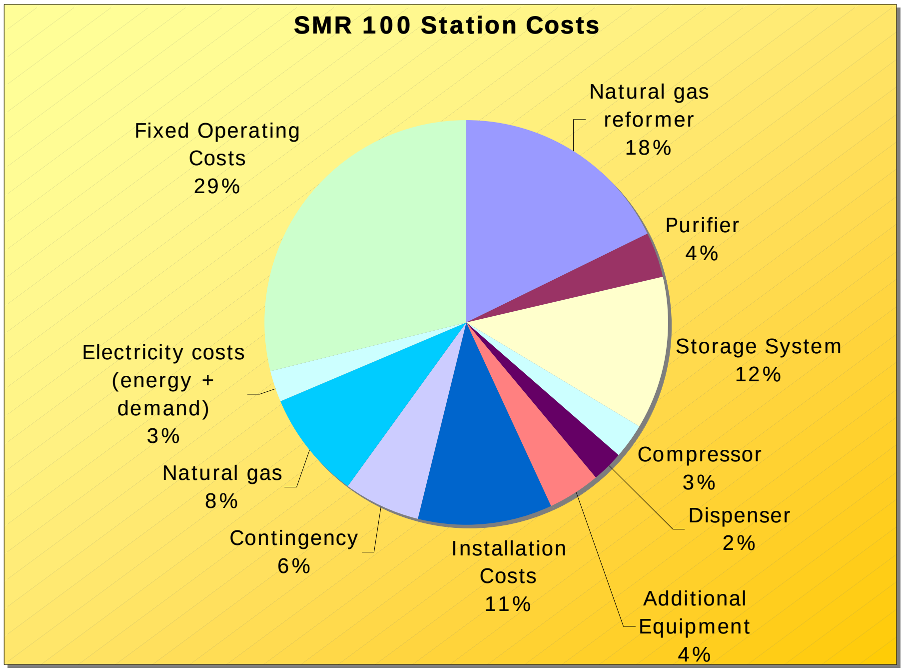

Figure 9. Costs for Reformer-type (SMR 100) Station

1.2.9 Sensitivity Analysis

A sensitivity analysis was conducted on the ten major variables in the model to determine each variable's effect on overall hydrogen cost. Table 15 shows the high and low values used for each variable in the sensitivity analysis. Figure 10 shows an example of the results of the analysis for a reformer-type station.

As can be seen in the figure, hydrogen price is most sensitive to capacity factor. This is also true for the nine other station types.

Table 15. Sensitivity Analysis

Parameter	Base Case	Bright	Bleak
Natural Gas Price ($/MMBtu)	$7.0	$4.9	$9.1
Electricity Price ($/kWh)	$0.10	$0.07	$0.13
Capacity Factor (%)	24%	31%	17%
Return on Investment (%)	10%	7.0%	13%
Rent ($/ft^2/month)	$0.50	$0.35	$0.65
Contingency (% of capital cost)	20%	14%	26%

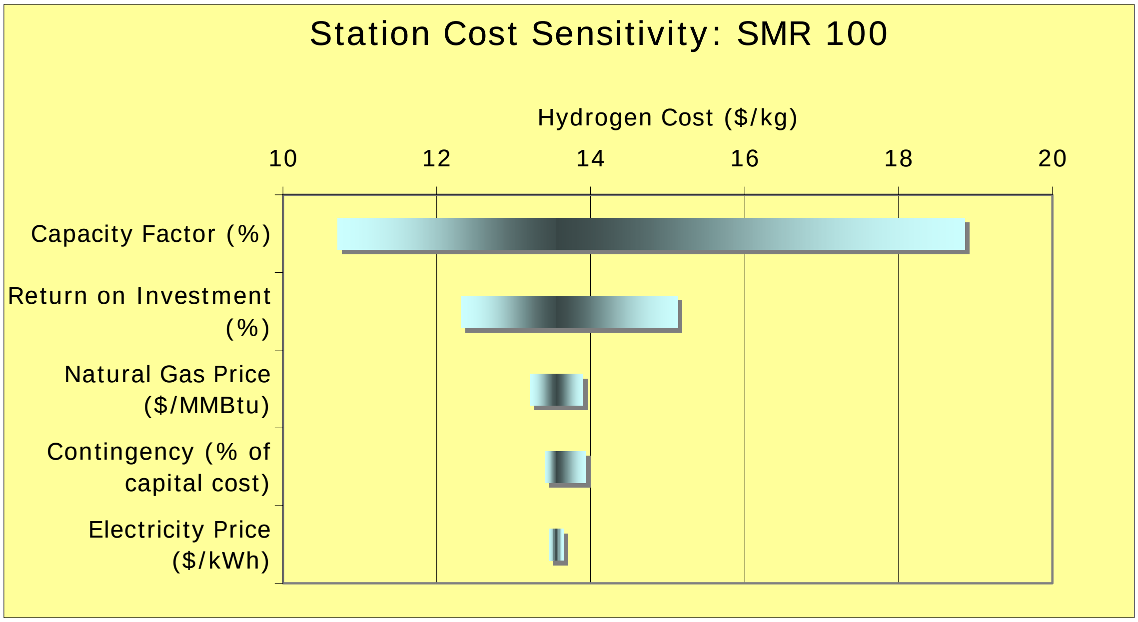

Figure 10. Sensitivity Analysis Results for Reformer-type (SMR 100) Station

For an electrolyzer-based hydrogen station with capacity of about 100 kg/day, energy cost makes up about 40% of the hydrogen costs. Electricity price of 10 cents or more per kilowatt, usually paid by residential users in California, contributes about $6.00 to the cost of hydrogen per kilogram. In California today, time of use (TOU) and interruptible service rates for large users of 500 kW ore more are between $0.05/kwh and $0.07/kwh with capacity factors in excess of 80% (e.g., SCE Schedule I-6, LAWDP A-3). With the demand management capabilities of electrolysis, these rates can be leveraged for hydrogen production.

As an example of the improving economics with scale, consider the unit cost benefit of increasing from a 100 kg/day electrolysis based system, the largest considered by the current analysis, to a 30 kg/day and a 200 kg/day electrolysis based system. Table 16 shows the relevant costs and the declining cost per unit of hydrogen from about $26 to $10 per kilogram of hydrogen produced.

Figure 11 shows the effect a drop in electricity price to $0.04/kWh has on hydrogen cost for electrolysis type station.

The benefits of scale-up on the cost of hydrogen are significant and realizable today, as a result of lower capital and operating cost contributions. Current manufacturers can deliver single electrolyzer stacks that generate up to 30 kilograms of hydrogen per hour, with approximately 1.8 MW of power input. These stacks can be added together to scale up to virtually any amount of hydrogen that is required, to meet the needs of large bus fleets or other vehicle fleets.

Table 16. Capacity Utilization and Cost

	Electrolyzer 30 kg/day	Electrolyzer 100 kg/day	Electrolyzer 200 kg/day
Analysis	Existing CaHH	Existing CaHH	Additional
Electrolyzer Price	$310k	$450k	$600k
Electricity Price	$0.10 /kWhr (Residential)	$0.10 /kWhr (Residential)	$0.065 /kWhr (TOU, Interrupt)
Station Annual Cost	$197k	$403k	$493k
Hydrogen cost/kg	$25.70	$15.80	$9.64

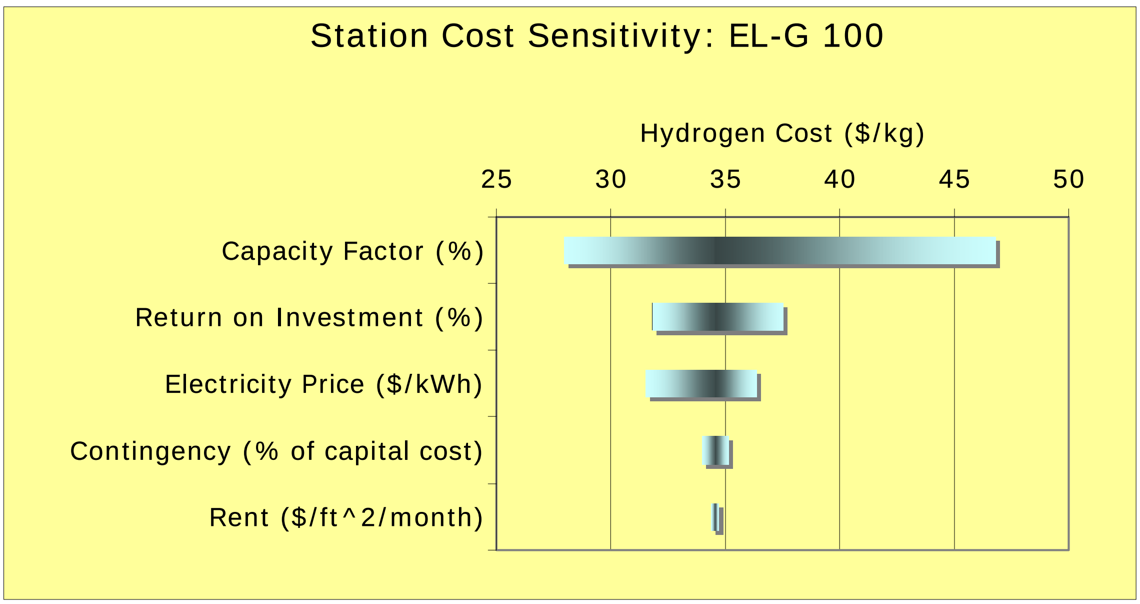

Figure 11. Cost Sensitivity for Electrolysis-type (EL-G100) Station

In order to decrease delivered hydrogen costs to $2.50 to $3.00/kg on the vehicle for hydrogen generation from renewable electricity, capital cost decrease from volume manufacturing, technology development and scale up must be realized. In addition, access to appropriately affordable power, lower installation costs and higher capacity factors on station infrastructure are required.

1.2.10 Conclusions on Cost Estimates

The Hydrogen Highway economic analysis leaves us with the following conclusions:

- Hydrogen fuel costs measured in $/kg will be higher at small stations that are burdened with high installation costs and low utilization of station infrastructure. However, small stations represent a low risk, low investment approach to achieve the state-wide build out of hydrogen infrastructure contemplated by EO S-7-04, to meet distributed loads with < 100 kg per day. Small size, low capacity factor infrastructure is consistent with expected fuelling requirements for early hydrogen infrastructure deployment.

- Lower hydrogen fuel costs will be achieved with hydrogen stations that have economies of scale in fuel delivery, likely requiring fleet applications for early station introduction.
  - Favorable electricity prices are available in some jurisdictions for large users (>500 kW) who have the flexibility to take advantage of TOU rates and interruptible service.
  - Fixed operating costs can be amortized over more delivered fuel for larger fuel stations.
  - Capital and installation costs decrease significantly per unit of output with increasing hydrogen energy station size.

It is because of the high cost of early introduction, low volume, low capacity factor infrastructure that the California Hydrogen Highway initiative is important. By supporting the early introduction of this infrastructure, California can create the economies of scale required for lower cost infrastructure and break the “chicken-and-egg” problem so often associated with hydrogen vehicles and hydrogen infrastructure.

To achieve the goals of the hydrogen highway initiative, a wide-spread infrastructure deployment is required that minimizes cost and creates distributed hydrogen availability.

In order to drive down hydrogen costs to make hydrogen a widely acceptable, commercially viable alternative, the hydrogen highway initiative will need to consider larger stations with greater capacity factors and lower unit costs for infrastructure.

In addition, this infrastructure can utilize TOU, interruptible rate schedules for electricity and benefit from lower cost renewable energy in the future. These favorable rates are available today in most utility jurisdictions (e.g., SCE Schedule I-6, LAWDP A-3)

High-Temperature fuel cell energy stations and pipeline-based stations deserve special consideration since they result in the lowest cost hydrogen. While applications for these specialty stations are limited to locations with an existing sizeable hydrogen demand, this existing hydrogen demand allows for much higher utilization of the energy station asset. In the case of high-temperature fuel cell energy stations, these stations would be sited at either commercial and/or industrial locations with a hydrogen demand currently addressed with delivered bottled hydrogen. The hydrogen generated by the energy station would be used primarily to displaced bottled hydrogen used at the facility, with a dispensing station available to fuel vehicles when and if needed. Since the costs of producing hydrogen using this technology ($5.60/kg) is lower than the bottled hydrogen costs ($6.00 to 7.00/kg) it displaces, this specialty station has the potential of being self-funded from the revenues produced by the sale of electricity, hydrogen and heat to the host facility. Although the high-temperature fuel cell option looks promising and involves the integration of two already commercially available technologies (fuel cell itself and PSA H_2 purification system), this type of unit has not yet been built and tested as an integrated system. Thus, the costs are expected costs and not field-tested costs.

Achieving the goals set by the U.S. DOE and Governor Schwarzenegger's EO for a sustainable hydrogen economy based on renewable energy will require a combination of efforts from industry and government, focused on technology and policy.

Policy initiatives that support renewable energy and hydrogen generation include:

- Extension of TOU electricity pricing to smaller industrial electricity users.
- Extension and harmonization of interruptible service rates across all California utilities and to smaller meter users (<500 kW) involved in the hydrogen highway.
- Power purchase agreements between renewable energy providers and hydrogen generators to provide appropriately priced renewable power and incentive for new renewable power capacity in connection with the hydrogen highway.

Technology developments underway in support of renewable energy and the hydrogen highway include:

- Decreasing cost of renewable power generating equipment by major wind turbine and solar PV manufacturers
- Declining costs for electrolyzer equipment capital cost, resulting from:
  - Product design simplification
  - Volume manufacturing
  - Implementation of lower cost materials
- Improved efficiency of electrolyzer / compression systems from current 60 kWh/kg to 50 kWh/kg with identified technology improvements.
- Decreased installation costs through repeat installations and learning by regulators and infrastructure providers.

With the combination of appropriate policy initiatives, technology advancements and eventual scale up in product size and manufacturing volume, the goal of a hydrogen economy that is sustainable and economical is readily achievable by 2020. The Hydrogen Highway initiative is an important and visionary catalyst for achieving this vision.

2. Financing Tools and Policies

2.1 Introduction

One of the Economy Topic Team's challenges was to identify and evaluate sources of capital that could be used to accelerate hydrogen fueling station deployment for the CA H2 Net.

The Economy Topic Team's early discussions aimed at developing funding policy recommendations were energetic but inconclusive. After consulting with the CA H2 Net Advisory Panel, the Economy Topic Team agreed that it would not attempt to achieve consensus on recommended funding measures. Rather than develop recommendations, the Topic Team agreed to identify suitable funding mechanisms and to evaluate each by summarizing its advantages and disadvantages (i.e., according to its "Pros" and "Cons").

This section of this Topic Team Report identifies and evaluates potential sources of funding to build and operate the CA H2 Net's fueling infrastructure. It does not address policies to directly stimulate or subsidize production and sales of hydrogen-fueled vehicles, which are covered separately by a TIAX report. Nor does it focus on research and development, although some of the measures cited, such as tax credits, would encourage such activity.

While the Economy Topic Team doesn't recommend specific funding measures, it does endorse development of a public-private partnership to attract and coordinate the combination of public and private-sector resources needed to accelerate the early growth of the CA H2 Net.

Given the general tenor of California's economy and concerns regarding the existing level of taxpayer burden, the Economy Topic Team sees the need for some funding to come from private financing sources, especially if the program is to succeed in "pushing the envelope" to accelerate the transition to a hydrogen and fuel cell economy. Nonetheless, the impacts of such private-sector funding measures on the business community must also be considered.

The Economy Topic Team began its deliberations with a bias towards relying on market-based policies to attract the flow of private capital to the CA H2 Net. Various market-based concepts, including franchising principles, were considered. However, the pace of market development for hydrogen vehicles and associated hydrogen fuel revenue streams at fueling stations is far below what would be needed to attract the levels of private investment needed to build the CA H2 Net.

For this reason, the Economy Topic Team endorses the use of tools other than purely market-based mechanisms for directing private-sector resources.

We also believe that there is a need for more broad-based revenue mechanisms to support the CA H2 Net. This is because the benefits of the CA H2 Net will be both *public* as well as *private* in nature. Reducing greenhouse gas emissions and reducing dependence on fossil fuels will benefit everyone in the long run.

The Economy Topic Team's "tool box" includes several bold initiatives capable of ensuring implementation of scenarios B or C. Because such bold initiatives will take time, near-term progress on the Hydrogen Highway fueling infrastructure may also require modifying existing government programs or mandating private-sector participation.

2.2 Background

We found it useful to think in terms of a financial "tool box" with different financing mechanisms divided into the framework pictured Figure 12.

The matrix of "tools" is divided into two basic columns, representing (a) private financing sources – i.e., resources from non-governmental sectors of the economy; and (b) public financing sources – i.e., fees, taxes or other revenue mechanisms derived by

Economy Team

"Tool Box"

	Private Resources	Public Resources
Market-Based Concepts	X	
Mandates	X	X
Cross-Subsidies		X
Direct / New Subsidies		X
Non-Profit	X	
Reinforcing Mechanisms	X	X

Distributed Energy Systems

Chip Schroeder
203-678-2316

Figure 12. Economy Topic Team Financial "Tool Box"

government from the general public. If the responsibility for financing the hydrogen fueling infrastructure is placed on all citizens, a general revenue mechanism is appropriate. But if the decision is to place financing responsibility primarily on specific economic sectors closer to the supply end of the economic stream, then it may be appropriate to implement specific mechanisms targeted at private sectors of the economy.

The six rows in Figure 12 correspond to various mechanisms (or tools) for influencing the flow of capital from private or public sources into the CA H2 Net. These six rows are: (a–b) **Market-Based Mechanisms** aimed at influencing the financial attractiveness of investment in the CA H2 Net; (c–d) **Mandates** that actively affect behaviors of various private or public actors; (e–f) **Cross Subsidies** that transfer some of the benefit of current subsidy programs from existing recipients to new recipients—namely, the participating service providers in the CA H2 Net (for example, transfer of a portion of existing gasoline tax receipts to the program); (g–h) **New Subsidies** that involve new taxes or other new revenue sources to enable the program; (i–j) **Non-Profit Organizations** with public-service or philanthropic missions that embrace environmental / energy sustainability or economic development goals; and (k–l) **Reinforcing Mechanisms**, such as awards and incentives which, while not sufficient to fund the fueling infrastructure, may contribute to the broader goal of accelerating development of the hydrogen economy.

2.2.1 Energy Stations and the CA H2 Net

In order to strengthen the financial attractiveness of the CA H2 Net, the Economy Topic Team supports the idea of enabling some hydrogen fueling stations to also serve as stationary power generation facilities, with additional revenues derived from electric utilities and/or their customers. The Economy Topic Team offers some specific ideas, below, and in Appendix G, for encouraging a constructive and mutually beneficial relationship between the CA H2 Net and the several regulated and public electric utilities in California.

Energy stations alone are not sufficient to implement the hydrogen fueling infrastructure, but they are a potentially important factor in determining its cost and accelerating its commercialization. Therefore we include facilitation of DG and energy stations in the list of primary funding mechanisms.

2.3 Market-Based Mechanisms

The Economy Topic Team examined a number of ideas with the goal of finding a way to attract purely private capital to the CA H2 Net. The market-based mechanisms we consider to be most promising derive from franchise concepts. We also considered such ideas as “green” credits and credit trading, but the value of credits depends upon the existence of fees or penalties applied to actors who do not voluntarily invest to reduce pollution but instead purchase credits associated with their emissions. Legislating penalties or fees is, in our view, a cross subsidy tool rather than a fundamentally market-based mechanism. Accordingly, we examine this concept in the cross-subsidies discussion in Section 2.7.

For similar reasons, we view tax credits as a subsidy. One could argue that tax credits are market-based because they have taxpayer costs only when private actors make investments in accordance with policy goals, but the reality is that those credits also diminish tax revenue, and thus represent a transfer of tax burden from recipients of the credits onto the general taxpayer population.

2.3.1 Franchise Concepts[2]

The private sector will invest in the CA H2 Net if such investments hold potential for competitive financial returns. In considering how capital formation has occurred in other emerging markets (cable television, biotech, cellular phones and wind power, to name a few) we have identified some basic franchise concepts that may have applicability to the CA H2 Net. These ideas encompass (a) limiting or *rationing market entry* — e.g., the McDonald's, or Federal Communications Commission (FCC) Radio Spectrum Auction, model; (b) *revenue sharing* among market participants — e.g., the Major League Baseball model, and (c) market *intervention to encourage new participants*—as when incumbent phone companies were prohibited from controlling more than 50% of any cellular phone market in order to enable smaller, entrepreneurial companies to enter and compete in such markets.

We exposed these ideas to a number of financial participants, including investment bankers and investment staff from the California Public Employees Retirement System (CalPERS) involved in their green investment initiatives. The view from the financial markets was quite uniform. Financial observers view the pace of hydrogen fueling demand growth as insufficient to satisfy private finance market requirements. That is, the returns, relative to the costs, are not seen as competitive against other, more conventional, investment opportunities.

However, at least one executive in a large energy company expressed potential interest in an auction of California hydrogen sales franchises. If enough large energy companies regard early-stage participation in the CA H2 Net as a strategic necessity, then an auction mechanism that limits strategic access to the CA H2 Net could raise significant capital.

Otherwise, there is little, if any, potential for meeting the immediate financing needs of the CA H2 Net with purely private capital attracted through purely market-based mechanisms.

[2] See Appendix H for a background discussion of franchises.

Pros:

- Financing the CA H2 Net with market-based capital incentives would best assure economic viability. The potential for uneconomic or stranded investment would be minimized, and the burden on public taxpayers would be avoided.
- Franchise fees, royalties, or other franchise-related income could be allocated to development of the CA H2 Net.
- Early entrants would have an opportunity to drive infrastructure concepts.

Cons:

- There is little practical potential in the near-term for attracting purely market-based financing for the CA H2 Net.
- Limiting competition could impede longer-term reductions in hydrogen and vehicles prices.
- A franchise brand identity would need to be developed, requiring significant education and communication effort.

2.3.2 DG/Energy Stations via Energy Market Reforms[3]

Hydrogen fueling stations could be combined with stationary power generation facilities, and derive additional revenues from corporate customers or electric utilities.

Utilities will play an important role in the CA H2 Net, not only as suppliers of electricity for electrolytic hydrogen, but also as purchasers of secondary power from those CA H2 Net facilities configured as energy stations. Utilities can be given market-based incentives to participate in the program if costs of the secondary power are not competitive, or they may be influenced by mandate. The CPUC's current distributed generation (DG) proceeding may be an opportunity to encourage development of hydrogen energy stations. (See Section 2.7.3, "Modify CPUC DG Rulemaking.")

One specific proposal is to create a new uninterruptible rate and service class for industrial and commercial customers. Such customers would have the right to request uninterruptible service from their utility on a negotiated contract basis to meet the critical load portion of their needs. (See Appendix A for further explanation of this uninterruptible rate class proposal.

Pros:

- Improves the potential profitability of the hydrogen fueling infrastructure.
- Provides hydrogen where customers need it.
- Improves driving efficiency by placing station in path of vehicle destinations.
- Helps meet generation and distribution requirements of overburdened grid.

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[3] See also Section 2.7.3 "Modify CPUC DG Rulemaking," below.

Cons:

- Would require complex, time-consuming regulatory reforms.
- Adding DG energy stations increases the overall cost of the hydrogen fueling infrastructure (although this depends on how one allocates DG energy station costs).
- Utilities are currently prohibited from investing ratepayer money in alternative fuels infrastructure (although use of shareholder funds is permitted.)
- Utility acceptance of two-way power flows and other reforms will require strong support from the CPUC and the CEC, and intense, prolonged public pressure.

2.3.3 Managing Strategic Business Relationships

The process of creating new markets and attracting capital to those new markets often involves new technologies and new business practices being grafted onto existing infrastructure. Such was the case with the formation of the cellular phone system. When the FCC set out to create a rational cellular phone marketplace, it recognized that smaller, innovative and entrepreneurial companies are important to implementing new business, but could be effectively frozen out of the market by incumbent market participants. Accordingly, the FCC specified that no incumbent could own more than 50% of the cellular service in any service area, and that the other 50% must be reserved for new participants.

Similar conditions exist in today's fueling marketplace. Distributed hydrogen generation and dispensing systems are being developed by a number of smaller technology-based companies and industrial gas companies. Major energy companies, who are critical to the deployment of a viable hydrogen fueling market, have vested interests in existing fuels and fueling infrastructure. Creating inducements and/or mandates for incumbents to accommodate and encourage smaller companies with admittedly disruptive ambitions will be a sensitive but important element of success of the CA H2 Net.

Pros:

- Incumbent energy companies have the marketing expertise and physical presence that are essential to a successful roll-out of the CA H2 Net, but smaller technology-based companies have the entrepreneurial drive to accelerate change in the marketplace.
- Companies may want to participate for image purposes.
- Companies may be willing to offer land, facilities for stations.
- Companies may be willing to co-fund a portion of the costs.

Cons:

- Energy companies have historically relied heavily on internal R&D to meet new process/product needs. With a few exceptions, the majors have not been active investors in hydrogen or fuel cell related development-stage companies. There will be real challenges in developing appropriate dialogue and collaborations.

- It will take a significant effort to identify candidate companies.
- Company locations may not correspond with infrastructure needs.

2.4 Mandates-Private Resources

2.4.1 Incumbent Supplier Mandates

It is within reach of the State of California to compel investments by energy companies and fuel suppliers into hydrogen supply infrastructures. Mandates could also be applied to motor fuel suppliers, industrial gas (hydrogen) companies, or other types of suppliers. One type of mandate would require incumbent fuel suppliers to increase the number of hydrogen fueling stations as vehicle penetrations reach certain levels. Another type of mandate would require them to add hydrogen fueling capability as a condition of obtaining new or renewed permits for their fueling facilities. A requirement that 3% of all fueling facilities add hydrogen capability by 2010 would result in 300 hydrogen facilities by that date. Such mandates could focus on non-attainment areas.

Pros:

- Bill would require only a simple majority vote in legislature.
- The Democratic legislative majority may support.
- Unlike some public funding resources, private funds can be used both for fueling station operating costs and capital costs.
- Incumbent suppliers are experienced builders/operators of fueling infrastructure.
- Incumbent suppliers may be able to leverage existing distribution infrastructure.
- Privately managed fueling station construction will be less time consuming.

Cons:

- Forcing companies to invest prematurely in uncompetitive technology may result in wasted or “stranded” investments. The cost of these investments will ultimately be passed along to consumers in the form of higher prices, or absorbed by the companies.
- Mandating near-term energy company implementation could freeze technology at less economic levels by diverting capital from longer-term research and development.
- This approach is divisive and will discourage cooperation by some stakeholders.
- Premature use of uncompetitive technology could sour consumer interest and harm long term prospects for hydrogen markets.
- Mandates have rarely resulted in making the “preferred” technology self-sustaining. Governments have poor track record at picking “winners.”
- Does not address concerns about costs of doing business in California.

2.4.2 Private Fleet Operators

Require private fleets to purchase or operate a quantity or proportion of hydrogen vehicles.

Pros:

- Increases density of vehicles to use infrastructure.

Cons:

- Fleets generally purchase lowest-cost vehicles, whereas early entry fuel cell or hydrogen vehicles will command premium prices.
- Fleet vehicle applications will have to be subsidized.
- Increased operating costs, stranded investments, etc.
- The State could not mandate private fleet participation without also addressing mandates for state and public fleets.

2.4.3 Private R&D Resources

Pros:

- Provides near term resources for station building
- Allows investigation of new and novel technology options
- Is a tax write-off to contributor
- Contributes to overall knowledge for potential commercialization of new technology

Cons:

-

2.5 Mandates: Public Resources

2.5.1 State and/or Local Agency Mandates

Require State and/or local agency fleets/garages to purchase hydrogen vehicles and deploy infrastructure that provides public access. Government fleet or fuel procurement standards might be employed.

Pros:

- Increases density of vehicles to use infrastructure throughout the State.
- Creates the incubator for a hydrogen fuel production and distribution.
- Can be implemented by Executive Order.

Cons:

- General Fund financing.
- Vehicles will have to be subsidized.

2.6 New Subsidies

2.6.1 State of CA General Obligation Bonds

General obligation bonds (GO bonds) are a form of long-term borrowing in which the state issues municipal securities and pledges its full faith and credit to their repayment. Bonds are repaid over many years through semi-annual debt service payments. GO debt repayment is continuously appropriated and therefore not included as a separate appropriation in the annual Budget Act.

GO bonds are used to finance public capital projects such as university building construction and water projects.

The California Constitution, (Article XVI, Section 1), requires that GO bonds be approved by a majority vote of the public and sets repayment of GO debt before all other obligations of the state except those for K-14 education. GO bond ballot propositions can be placed before voters by the State legislature. There is no California statutory or constitutional limit on the absolute level (or any other measurement) of state debt.

GO Bonds may be either self-liquidating or non-self-liquidating. Self-liquidating GO bonds are backed by project-generated revenue streams and do not affect the State's credit rating because the bond market does not include them when calculating debt service ratios. An example of self-liquidating GO bonds is the veterans' home loan program, where expenditures are reimbursed through mortgage payments. The California Constitution authorizes GO bonds with up to 50-year maturities, but the economics of the bond market usually dictate that bonds be issued on a 20- to 30-year basis.

GO issues have the highest credit quality in the state and therefore the lowest tax-exempt rates. The true interest cost of 2004 GO borrowings has been approximately 4.6 percent, (averaging all maturities). With the recent approval of a $15 billion bond to help resolve California's budget crisis, California GO bond ratings have bounced back from historic lows.

Each spring and fall, the State Treasurer's Office, which generally acts as sales agent, prepares a bond sales calendar for the following half of the calendar year. Preparation, sale and closing of a GO bond issue takes only three months, but scheduling limitations imposed by the budget process and other factors make it necessary to request bond sales 8 to 12 months in advance.

To meet cash needs before bonds are issued, GO programs may require interim financing through loans from the Pooled Money Investment Account or the General Fund, or through the issuance of tax-exempt commercial paper or other short-term negotiable instruments. The purpose of interim financing is to meet project cash flow needs for expenses incurred after project authorization, but prior to the issuance of long-term debt instruments. Unless statute provides otherwise, GO bond projects are eligible for state-funded interim financing.

Pros:

- Policymakers and the public may prefer GO bonds to new taxes.
- A public referendum would give the Governor an opportunity to "take it to the people" and thereby elevate the issue and better inform voters.
- CA H2 Net funding could be bundled into larger transportation or environmental bond proposals.

Cons:

- GO bonds require public referenda.
- GO bonds can only be used for capital, (not operating), costs.
- GO bonds are used to finance State-owned facilities. Private ownership of California's hydrogen fueling infrastructure would limit the use of GO bonds for the CA H2 Net.
- Many State of California bonds have been issued recently. Issuing additional GO bonds could negatively affect the terms of subsequent bond issues.
- CA H2 Net GO bonds would have to compete with bonding proposals for other purposes, such as education, health and social services.

2.6.2 State of California Revenue Bonds

Revenue bonds (or enterprise revenue bonds) are a form of long-term borrowing in which the debt obligation is secured by a revenue stream produced by the project. Because revenue bonds are self-liquidating and not backed by the full faith and credit of the state, they may be enacted in statute and therefore do not require voter approval.

Lease-revenue bonds are a variant of revenue bonds used in the state's capital outlay program. The revenue stream backing the bond is created from lease payments made by the occupying department to the governmental financing entity which constructs the facility. Generally, this entity is Public Works Board or occasionally a Joint Powers Authority (JPA) of which the State is a member. The financing authority constructs the facility, issues financing bonds, and retains title to the facility until the debt is retired.

The term of lease-revenue bonds cannot exceed the useful life of the facility. Lease-revenue bonds may not be issued for any project for which a lease cannot be created. (Without a legally enforceable lease, there is no security for the issue.)

Lease-revenue bonds do not require voter approval because the transaction is set up to mirror a typical financing lease, i.e., lease payments are due on a year-to-year basis and required only if the facility can be occupied. In contrast to GO bonds, annual appropriations are necessary for lease-revenue debt service. However, the obligation to pay is not extinguished if appropriations are not provided.

Pros:

- Do not require public referenda.

Cons:

- Revenue bonds require a secure future revenue stream, but the CA H2 Net is not expected to produce operating income.
- Securing revenue streams other than operating income is problematic and, in many cases, (e.g., fuel tax hike or carbon tax), would require support from two thirds of the legislature.
- Revenue bonds can only be used for State-owned properties.
- Can be more difficult to float than GO bonds depending on how the underwriters evaluate the proposed revenue stream, (new or prospective streams could be discounted substantially).
- Issuing additional revenue bonds can affect credit ratings for the State's debt securities.

2.6.3 Carbon Tax

A tax on all carbon consumed in California, including utility fuel consumption, natural gas and heating oil, rather than a tax on only gasoline could provide revenues for building the CA H2 Net. If all hydrocarbons consumed were subject to a tax aimed at generating the same $45 million per year discussed above, the cost to consumers would be far lower on a gallon-equivalent basis then a transportation fuel-only tax.

Pros:

- Environmental policy makers have long advocated a tax on carbon as one of the most effective instruments for discouraging greenhouse gas emitting activity.
- A carbon tax is an opportunity for California to demonstrated leadership by being the first to move beyond advocacy on a general carbon tax.
- A carbon tax can be structured to share the burden between the public and private interests.

Cons:

- New taxes are unpopular with taxpayers, i.e., consumers, and will be politically problematic, especially if fuel prices remain high.
- No government has yet implemented a broad-based carbon tax, (other than emissions trading schemes applicable to large industrial and utility facilities).
- Would discourage cooperation from key stakeholders, e.g., fuel suppliers.
- Would require a complex, time-consuming overhaul of state bureaucracy, including tax collecting procedures, rules and programs.
- Any such tax increases will require a constitutional amendment, (2/3 vote in each House and a vote of the people in a statewide election).
- Probably cannot be implemented in time to fund 2010 fueling infrastructure.
- Increases transportation, electricity and natural gas costs for consumers and industry, eroding their purchasing power.
- Tax is regressive, placing disproportionate burden on low income households, especially the poor and elderly.

- Some studies say that a carbon tax would slow economic growth by reducing personal consumption and business investment.
- Increased energy costs will impact California's business competitiveness.
- Taxpayers may question the link between increasing home heating costs due to a carbon tax in order to fund a network of hydrogen vehicle filling stations.

2.6.4 Increase State Fuel Excise Tax, (or Impose a "Fee")

Transportation fuel (gasoline and diesel) sold in California amounts to 18 billion gallons per year (15 billion gasoline, 3 billion diesel). A quarter-cent per gallon increase in State fuel excise taxes would yield $45 million per year for the CA H2 Net, more than enough to finance the 250 hydrogen fueling stations under scenarios B or C. The State may choose to define a quarter-cent per gallon "fee" on gasoline and diesel fuel, (vs. a tax increase). The fee would have to be spent on programs that mitigate problems associated with gasoline and diesel fuel consumption (e.g., health impacts, environmental, etc.).

<u>Pros</u>:

- Compared to the amount of recent fuel price swings, half of a cent per gallon is scarcely noticeable.
- The fuel excise tax has not changed since January 1994.
- Legislative coalitions to increase fuel taxes, (by 5 to 6 cents per gallon), to meet transportation infrastructure needs have recently been active.

<u>Cons</u>:

- Fuel taxes are considered by many to be regressive.
- The fuel excise tax has not changed since January 1994.
- Represents a tax increase, which is problematical politically, especially if fuel prices remain high.
- Fuel tax increases are unpopular with the motoring public.
- Excise tax revenues cannot be used for this purpose without amending the state constitution. Amending the constitution would require a 2/3 vote in each House and a statewide referendum.
- Funding for transportation (including the State fuel tax) is already grossly oversubscribed.

2.6.5 Increase Vehicle Registration Fees

Pay for hydrogen fueling infrastructure development through an increase in the vehicle registration fee. A registration fee increase of about $1.65 per vehicle would raise about $45 million annually. In 2003-04, motor vehicle registration fees averaged about $45 per vehicle. Major fee increases occurred in 2004 to ensure the solvency of the Motor Vehicle Account. (See Section 2.7.4, "AB 2766 Funds".)

Pros:

- There is a broad base so a small fee can generate significant revenues over time.

Cons:

- Registration fees are politically sensitive user fees.
- Legislation would be required to increase the fees.
- Taxpayers may question the link between increasing registration fees for all vehicles in order to fund a network of hydrogen vehicle filling stations.

2.6.6 Establish Hydrogen-Centric State Grant Program/Fund

Define a new State program (modeled after Carl Moyer Program) that creates multi-year state funding for hydrogen programs consistent with the Integrated Energy Policy Report document. These funds can be used for voluntary projects related to infrastructure, hydrogen production, as well as vehicle incentives for light-duty or heavy-duty vehicles

Pros:

- Carl Moyer Program is providing diminishing environmental benefits as new diesel technology approaches cleaner alternative fuel technology.
- Carl Moyer Program for new products may be obsolete by 2010 (U.S. Environmental Protection Agency (EPA) and California Air Resources Board (ARB) standards equal and extremely low).
- California's goal to develop alternatives to petroleum for energy security fits well with the goals of the CA H2 Net.

Cons:

- Probably cannot meet cost-effectiveness criteria, which is key principle embodied in the Carl Moyer Program.
- Could siphon funding from more cost-effective programs designed to reduce criteria pollutants.
- Who needs a new program?

2.6.7 Increase in State Sales Tax

Potentially exploits the largest revenue base in the state with the lowest unit charge. An increase in State sales tax of one tenth of a cent per dollar would raise about $440 million annually.

Pros:

- "Bold" initiative to raise all dollars required.

Cons:

- It is still a tax increase.
- Sales tax increases of $0.001 may be difficult/impossible to administer.
- Intense demand for State sales tax revenues.

2.6.8 State Tax Credits

Tax credits can offer a positive approach for encouraging development of the hydrogen highway network. Investment tax credits are one mechanism that would encourage private investment in infrastructure by reducing the cost for investors. Tax credits could be used to encourage more R&D, too. Tax credits could also be structured as sales tax credits or refunds providing flexibility to expedite the creation of consumer demand or private infrastructure construction.

Private companies have indicated that they could make R&D contributions toward achieving Scenario A goals of the program. These resources could be used for technology demonstration activities and help grow the number of stations in the CA H2 Net.

New tax credits would reduce revenues at a time of fiscal difficulty. However, these activities may qualify for the R&D tax credit, at both the state and federal levels. If a new credit is desired, new legislation should eliminate other tax credits to achieve revenue neutrality.

Also consider (a) tax credits for homeowners for home H_2 fueling appliances or, (b) tax credits for rental car fleet adoption of hydrogen.

Pros:

- Offers an approach that encourages cooperation and collaboration on the part of companies receiving credits without burdening any particular stakeholder.
- Investment tax credits are a common mechanism used at both state and federal levels.
- Investment tax credits for corporations are not well understood by the general public and can be implemented without requiring public referenda.
- Using public resources is consistent with the idea that the general public will realize some benefits from the hydrogen highway.

Cons:

- State budget deficit makes it politically difficult to establish new credits that reduce the general fund.
- Investors need to have net revenue to take advantage of such credits.
- Tax credits may provide significant tax benefits to companies that would undertake these activities anyway.

2.7 Cross Subsidies

2.7.1 Redirect a Share of State Fuel Excise Tax Revenues

Transportation fuel (gasoline and diesel) sold in California amounts to 18 billion gallons per year (15 billion gasoline, 3 billion diesel). A $0.0025 per gallon of State fuel excise tax revenues redirected to the CA H2 Net would yield $45 million per year, more than enough to finance the 250 hydrogen fueling stations projected by Scenarios B or C.

Pros:

- Proceeds from tax or fee on petroleum products can be used to solve the problems of petroleum dependence, climate change emissions.
- Total fuel tax revenues in 2003-04 were about $3.32 billion, so $45 million represents a relatively small fraction of the existing revenues.

Cons:

- There is substantial pent-up demand for State fuel-tax revenues to fund un-met transportation infrastructure needs.
- It is doubtful that the state can absorb such costs and redirect existing revenues, considering its structural budget deficit.
- Excise tax revenues cannot be used for this purpose without amending the state constitution. (?)
- Consumer backlash against new taxes on petroleum in a $2.00+ gasoline world.
- Too visible “vote for new taxes” for legislators in a $2.00+ gasoline world.

2.7.2 Redirect a Share of CPUC “Public-Purpose” Surcharge

Utilities collect a Public-Purpose Surcharge from ratepayers that is used to fund energy efficiency and other types of public goods research programs. These funds cannot now be used for transportation projects. The majority of these funds go to agencies and institutions and are not spent by the utilities directly. Allowing the utilities to keep a major portion of these funds and spend them on transportation related projects could assist development of research and demonstration programs for on-site production of hydrogen through natural gas for gas utilities and hydrolysis for electric utilities. Funds can also be used to fund hydrogen fueling, R&D, and Codes and Standards.

Pros:

- Would be a legitimate public purpose endeavor for the state to pursue.
- The potential exists to collect more public purpose surcharge money from gas utilities.
- Key R&D and demonstration activities involving hydrogen production from natural gas, fuel cell DG, energy station concepts, and hydrogen from electricity could be funded from existing programs.

Cons:

- California law specifically excludes use of these funds for transportation, so legislative action will be required, (although if the initiative focuses narrowly on energy stations that co-produce electricity and hydrogen, statute changes may not be needed.
- Public purpose surcharge is for R&D – whereas CA H2 Net would be a large demonstration and commercialization activity.
- Need to change the CPUC Code by legislative effort to allow investor owned utilities to spend R&D funds for transportation programs.
- Would displace other effective work already being covered by the Surcharge and disrupt existing criteria for ranking proposed projects by cost effectiveness.
- Municipal utilities don't pay public purpose surcharge – therefore a program that only charges investor owned utilities is unfair.

2.7.3 Modify CPUC DG Rulemaking

The CPUC has a major proceeding underway regarding DG for California. Funding in the order of $125 million per year has been achieved over the last four years. But hydrogen fuel cells are just part of the DG mix being encouraged, and they aren't always cost-competitive with other DG technologies. The definition of DG could be modified to include co-production of electricity and hydrogen for purposes of fueling vehicles, (instead of just heating and cooling generated from waste heat). Revising the DG rules to create a new category specifically addressing fuel cells operating on natural gas to co-produce hydrogen and electricity could accelerate deployment of energy stations. Incentives to fund the capital costs associated with hydrogen generation could be increased above the current level of $2,500/kW.

Pros:

- Fuel cells are already accounted for in DG program.
- Opportunity to change guidelines so co-production of hydrogen for vehicles qualifies the same as production of heating/cooling from co-generation.
- With proper incentives from CPUC, end-users (rather than utilities) could own DG facilities.

Cons:

- Current barriers to utilities owning and operating DG facilities.
- Would require greater incentives than currently available for fuel cells to be competitive.
- Higher incentives for fuel cells would displace more cost-effective DG technologies.

2.7.4 AB 2766 Funds

Local air quality programs are funded by motor vehicle registration fees. State law authorizes air districts to assess these fees to fund implementation of the California

Clean Air Act (CCAA) and to support motor vehicle air pollution control programs at the local level. These funds support many varied programs that reduce motor vehicle emissions and demonstrate new clean air technologies. Local agencies approves the criteria and guidelines on how these funds can be spent. Local agencies would have to the criteria and guidelines to include a funding priority for the hydrogen highway network. In 2004, AB 923 was passed by the legislature and signed into law by the governor. AB 923 increased the motor vehicle registration fee from $4 to $6 to raise a potential of $55 million to fund the Carl Moyer Program, school bus replacements, and retrofits, scrappage, and agricultural engine programs. The potential exists to allocate a portion of the vehicle registration fees for the hydrogen highway are potentially increase registration fees to do the same.

<u>Pros</u>:

- Hydrogen highway is a program to bring long-term emissions relief to California.
- Uses vehicle registration fees for desirable environmental gains.
- Fees on vehicle registration can be directly linked to air quality improvements.
- AB 2766 funds have been used to support clean air technologies.

<u>Cons</u>:

- May require an increase in the vehicle registration fee-politically sensitive to consumers.
- With no increase in vehicle registration fee, Hydrogen Highway will impact potentially more cost effective air quality programs at the local level.

2.7.5 Federal Funding Sources

Many federal departments are required to fund state-oriented and state-initiated policies. In many cases, the laws also require state matching funds. Often, these programs are active for 5 to 6 years before they are reconsidered in Congress. Following is short list of potential federal funding sources:

- U.S. DOE: Work with DOE to provide greater hydrogen deployment monies to California and make sure their spending is coordinated with the Hydrogen Highway plan. Encourage DOE to develop planning grants for hydrogen infrastructure that are distributed for local and county use.

  DOE administers R&D programs not only in hydrogen but also in renewable energy technologies. The University of California manages three National Laboratories funded by the DOE. The Lawrence Livermore National Lab, for example, has been the home for much of the DOE's hydrogen research for more than 40 years. Outside the State, but still managed by the University of California is Los Alamos National Lab. Within California, NASA, JPL, and others are receiving federal funds. Meanwhile, national laboratories such as Sandia National Laboratories and the National Renewable Energy Laboratory contract for research work in California.

- The DOD will continue to spend on hydrogen-fueled transport systems, and state matching funds may be deployed to attract more federal R&D money. DOD has a large physical presence in California, and an estimated 60 DOD bases may be slated for closure under the next Base Closure Commission due to adjourn in 2005. Closures will free up valuable real estate and the DOD will likely devote funds to the conversion of the bases as it did in the early 1990s. Furthermore, active California facilities such as the naval bases and the Post Naval Graduate School in Monterey are important resources for the State. Redirecting or focusing these resources on hydrogen would be an important strategy.

- U.S. EPA: concern with environmental protection.

- U.S Department of Labor: concern with training future workforces with matching state funds for job training.

- U.S. Department of Education: provide leadership and education for new careers especially with an emphasis on science and technology(ies).

- U.S. Department of Commerce: concern with promoting domestic and foreign business opportunities. But also has the National Institute for Standards and Technology (NIST) which establishes codes and protocols for industry(s).

- U.S. FAA's VALE Program provides funding for alternative fuel vehicles (including H2) operating from airports. It can also fund refueling infrastructure, although the FAA is skeptical of hydrogen vehicles' pollution-reducing cost effectiveness (vis-a-vis competing alternative fuel vehicles). It may be possible to work out CA H2 Net-specific agreements with FAA whereby VALE funds are matched with other funds.

- National Science Foundation: among several federal research institutions that conduct basic research on contemporary and future issues.

<u>Pros</u>:

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<u>Cons</u>:

- State revenues from federal grant programs are unpredictable.

2.7.6 Air Quality Penalties/Fees

Penalty fees for air quality infractions are collected by the ARB and air pollution control districts around the State. These penalty fees are reallocated to viable air quality programs. A portion of these monies (percentage) could be set aside to fund Hydrogen Highway projects within local jurisdictions.

Pros:

- Since penalties are not something that can be anticipated, they could provide incremental funding for the hydrogen highway.

Cons:

- There is no steady and reliable stream of penalty revenues so depending on this revenue stream could be problematic.
- Local districts usually find more immediate uses for this funding.

2.8 Non-Profit

The California State Association of Counties (CSAC) Finance Corporation, itself a non-profit corporation, provides financing to local agencies, non-profit organizations and private corporations engaged in public benefit projects.

2.8.1 CSAC Finance Corp. – CaLease Private Placement Finance Program

Under a Joint Powers Authority with the State, the CSAC may issue bonds on behalf of local agencies for capital projects. CalLease has issued bonds for individual projects costing up to $7 million, but there is no upward limit. Collateral for the tax-exempt bonds, which are placed with private institutions such as Bank of America or GE Capital Corp., is the equipment purchased with proceeds from sale of the bonds. A standby letter of credit from the State would expedite this process.

Pros:

- Burden of repayment falls on local agencies.

Cons:

- Private lenders may not accept hydrogen fueling equipment as collateral
- Burden of repayment falls on local agencies.

2.8.2 CSAC Finance Corporation Small Issue Public Benefit Program

CSAC can assist nonprofit organizations and manufacturers in financing projects by privately placing tax-exempt notes with qualified institutional buyers. The program provides access to low-cost, tax-exempt markets at fixed rates with flexible terms. These bond issues are typically up to $5 million. Local agencies and private companies would be eligible to use these funds for projects with societal benefits such as fuel cell/electrolyzer projects. Total amount available via this program: ~ $45 million annually. Stand-by letter of credit from the State can expedite this process.

Pros:

- Low-cost tax exempt financing for early-adopters.

Cons:

- Bonds must be repaid.
- Hydrogen projects would compete with other public-benefits projects for limited funding.

2.8.3 Public-Private Partnerships

Identify, assess and access existing nonprofit programs, (or establish new nonprofit programs), that combine public and private capital resources to develop the hydrogen fueling infrastructure.

Options include participating in alternative fuels, innovation, and transportation-specific matching grant programs; recruiting businesses to meet private-sector cost sharing requirements in the context of Industry Driven Regional Collaboratives or grant applications to federal agencies; securing low-interest loans and tax-exempt contributions from private foundations whose missions are aligned with the goals of the California Hydrogen Highway.

Pros:

- Facilitates and expedites industrial progress by leveraging publicly funded programs.
- Enables public outreach and increases awareness of end-users about the hydrogen economy and hydrogen technologies.
- Demonstrates a creative and collaborative approach toward developing alternative energy.
- Provides fiscal venue for private foundations to make directed monetary contributions for the procurement of state tax credited infrastructure components.
- Creates new jobs and enhanced workforce skills, resulting in increased tax revenues, with the development and delivery of private industry training by publicly-funded programs.

Cons:

2.9 Reinforcing Mechanisms

- Monetary awards for technical accomplishment.
- Streamlined and simplified codes and standards.
- Recognition awards (from the Governor) for practical accomplishment.
- Mandates for H_2 use and fueling capability at high volume sites: airports, seaports, mail facilities. [4] Mandates for bus and specialty vehicle use of hydrogen.
- Require all hydrogen fueling facilities in the state to be available to all safety-certified users.

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[4] Airports and local authorities across the country have recently encouraged the use of electronic/ battery powered ground equipment in non-attainment zones. There would likely be resistance to another mandate to replace a new fleet of battery powered vehicles with hydrogen powered vehicles.

- Include hydrogen vehicles/power generation in state renewable portfolio standard RPS regimes.
- Eliminate all taxes / fees / restrictions for hydrogen-fueled vehicles and fuels: fuel excise and sales tax, registration fees; tolls; parking.
- Require electric utilities to provide discounted rates for power used in H_2 production.
- Require gas utilities to provide discounted rates for gas used in H_2 production
- Residential electric / gas discounts for home fueling appliances.
- Create Hydrogen / Renewable Energy Infrastructure Development Fund.
- Indemnify hydrogen equipment suppliers, vehicle OEMs, and/or fueling stations against certain levels or types of liability claims.

2.9.1 Vehicle Development Program with OEMs

The state should consider contracting with OEMs for design, production, delivery of vehicles to California so that the hydrogen highway can be fully utilized. These contracts will guarantee that OEMs are working to deliver to California's expectations. Contract funds vs. vehicle incentives at time of delivery my do more to stimulate OEM activity.

Pros:

- Front-end development by OEMs requires a significant investment.
- State funding can assure the public that OEMs are working to deliver near-term products.
- Defines a new public/private partnership.

Cons:

- OEMs may reject saying they are already going as fast as they can.
- Why should the State be so involved with defining products and technology?

3. Potential Hydrogen Fuel Benefits

Hydrogen is often called the energy of the future because of its potential to solve air quality problems and reduce the economy's dependence on petroleum. These two problems have been studied extensively and the literature contains many point of views and varying assessments of the benefits from solving these problems. The problems are complex, multi-faceted, and diversely cover petroleum, natural gas, coal, nuclear energy, and renewable sources.

The Economy Team used existing studies to initiate a discussion on the two topics. Expectedly, there was a diversity of viewpoints among the members of the Economy Team as to the validity of the assumptions and results presented in the literature. The Team did not do its own independent study. Specific studies of future hydrogen fuel markets would be needed to assess the full environmental and national benefits of switching to hydrogen. The estimation of these benefits help justify the necessary fiscal resources, and adopting policies discussed earlier in this report to ensure the success of California Hydrogen Highway Network. The discussion that follows is an assessment of the literature and some of the current views and estimates of benefits of reducing air pollution, and assessments of subsidies that petroleum fuels receive under current federal and state policies.

3.1 Air Pollution Impacts and Costs on Human Health

Primary goals of California's Hydrogen Highway Network as laid out by the Governor's Executive Order include reducing air pollution and greenhouse gases as well as reducing our dependence on petroleum and high carbon content fuels.[5] One source of air pollution is petroleum based fuels. The pollution from these fuels can impact human health and overall air quality in many ways - from 'upstream' refinery emissions, to transport by truck or pipeline, to localized health impacts from mobile source emissions, to regional health impacts from smog that shrouds metropolitan areas around the country. The emissions can result in an array of negative public health impacts including asthma, respiratory disease, cancers and even premature death.

The external health costs to Californians from our current petroleum dependent economy serve as an important backdrop for the need to transition to a cleaner alternative.[6]

The air pollution costs, which run into the billions, point to the significant indirect subsidy that currently supports petroleum fuels. Although costs to purchase hydrogen at the pump today may be higher than a gallon of gasoline or diesel equivalent, the playing field becomes more level when the external costs from high carbon content fuels are

[5] 'Executive Order S-7-04 by the Governor of the State of California', signed April 20, 2004.

[6] Externalities are unanticipated side effects or spill over effects arising from the production and/or consumption of goods and services for which no appropriate compensation is paid.

accounted for and 'internalized'. Current and future key stakeholders that guide California's Hydrogen Highway Network must incorporate externalities such as air quality impacts on human health into all phases of discussion, analysis and final decision making.

3.2 Health Cost Studies

In the past decade, a host of studies have been conducted on how human health harms associated with petroleum uses translate into health care costs. For the most part, these studies were conducted independently and consequently focused on disparate regions in the United States; operated under different assumptions, data sources and definitions; and, evaluated different pollutants and externalities.

Table 17 summarizes a subset of the studies that specifically generated estimates of health care costs due to motor vehicle emissions. These studies are referenced time and time again in various professional papers, media articles and other reports which summarize various components of the health impacts from the lifecycle of petroleum uses or, more often, the social costs of motor-vehicle use. The joint California Energy Commission and California Air Resources Board AB2766 Petroleum Reduction report chose Delucchi's estimates for the monetization of health impacts from vehicle emissions.[7]

Table 17. Annual Health Costs Due to Conventional Motor Vehicle Emissions

Study	Region	Pollutants Evaluated[a]	Annual Health Costs[b]
McCubbin and Delucchi (1996 & 1999)	U.S.	CO, NO_2, O_3, $PM_{2.5}$, PM_{10} and Toxics	\$26 to \$394
Mackenzie, et al. (1992)	U.S.	Illness due to Air Pollution	\$14
Small and Kazimi (1995)	South Coast Air Basin	PM_{10} and O_3	\$5 to \$27
McCubbin and Delucchi (1996 & 1999)	Los Angeles	CO, NO_2, O_3, $PM_{2.5}$, PM_{10} and Toxics	\$7 to \$110

[a] CO = carbon monoxide, NO_2 = nitrogen dioxide, O_3 = ozone, $PM_{2.5}$ = particulate matter smaller than 2.5 μm, and PM_{10} = particulate matter smaller than 10 μm.
[b] Presented in billions of 2004 dollars.

3.3 Limitations and Variability of Cost Estimates

Given the inherent difficulties in quantifying health impacts, there are a variety of limitations to the studies presented above. The studies chosen focus on health care

[7] 'Appendix A: Benefits of Reducing Demand for Gasoline and Diesel (Task 1)', Consultant Report, California Energy Commission and California Air Resources Board, May 2003, p. 3-8.

costs in the U.S. due to petroleum uses since 1990. Studies are not considered prior to this date to minimize the risk of outdated cost estimates and to capitalize on the most improved cost estimate methodologies.

The health care cost estimates presented in the studies reviewed differ, in some cases, by billions of dollars - even for studies attempting to evaluate the same facet of petroleum usage byproducts. There are many reasons for the large variation in cost estimates including differences in:

- *Pollutants evaluated* (e.g. different subsets of criteria pollutants evaluated)

- *Data sets or modeling techniques* (e.g. a study performed based on a past year's air quality data versus a study estimating costs based on predicted air quality in the future; or, using air quality data from one specific region or station versus an average over many regions)

- *Thresholds of comparison* (e.g. the difference between calculating costs based on a 100% reduction in motor vehicle emissions versus attaining National Ambient Air Quality Standards - NAAQS[8])

- *Interpretations of and data variations in clinical and epidemiological studies on the health effects of the various pollutants* (e.g. for particulate matter (PM), epidemiological studies tend to relate health effects to an undifferentiated mass of particles. Researchers estimating health costs have to decide which types and sizes of particulates are the most harmful and should be included for analysis)

- *Assumptions on key parameters such as mortality* (e.g. the dollar value given to the loss of a life)

For these reasons, cost estimates in independent studies that appear to have the same description of costs may in fact present incomparable cost estimates. Nevertheless, these studies, when taken in sum, display the alarming magnitude of external health costs in the state of California, and, most importantly, indicate dangerous impacts to our health – adults, children and the elderly alike.

There are also a number of reasons why the health cost estimates presented in these studies may err on the conservative side. The following are variables that are often not taken into account in such studies which support this conclusion:

- Larger and older vehicles as well as vehicles with ineffective emission controls have greater emissions per unit of travel. These must be included in order to accurately represent the motor vehicle population and resulting emissions.

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[8] Although a few of the more comprehensive studies focus on a 100% reduction of certain pollutants, these costs in reality may not deviate very much compared to cost estimates based on attaining NAAQS standards. Theoretically, additional health care costs when air quality standards are met should be minimal. Studies such as Delucchi's look at a 100% reduction of emissions based on the assumption that there are health effects at concentrations below the ambient air quality standard.

- Catalytic converters are ineffective when cold, so emissions are greater for short trips (this is significant considering that almost 65% of automobile trips are less than 10 miles long). Average emissions may be calculated based on a vehicle that is already 'warmed up'.

- Climate change, ozone depletion and acid rain emissions have costs regardless of where they occur.[9]

- Mounting evidence suggests that ultra-fine particles (less than 0.1 micrometer in diameter) are the main culprits of health impacts. Diesel exhaust is a significant contributor. As more and more scientific research is unveiled, there is increasing evidence of the direct link between particulate pollution and serious health impacts.[10]

- Other poorly regulated sources of emissions that must be taken into account include marine vessels, locomotives and off-road equipment, which often run on some of the 'dirtiest' fuel in the U.S.

These limitations highlight areas that could be incorporated into analyses in the future and serve as a reminder that the estimates presented herein should be taken as a relative measure of the negative impacts of petroleum uses on health in the state of California.

3.4 Societal Cost of Gasoline

Externalities such as those described above are not reflected in the price of gas at the pump. Other externalities, such as health impacts from refinery emissions, greenhouse gas impacts, damages to water and crops and noise pollution, are also not captured fully by the price at the pump. Some studies have concluded that the real cost of a gallon of petroleum based fuel such as gasoline could range from $5.60 to as high as $15 per gallon.[11] Avoiding these staggering costs to society should warrant state investment and the allocation of resources necessary to successfully roll out a hydrogen highway network. If this issue is not addressed, we will be left with an uneven playing field between subsidized petroleum-based fuel and an unsubsidized equivalent of hydrogen.

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[9] ' Transportation Cost and Benefit Analysis – Air Pollution Costs', Victoria Transport Policy Institute (http://www.vtpi.org)

[10] PMs are fine particles that can penetrate deep into the lungs and aggravate respiratory problems. A large proportion of these costs are due to respiratory illnesses caused or made worse by airborne particulate matter which is responsible for 9,300 deaths, 16,000 hospital visits, 600,000 asthma attacks and five million lost work days each year in California.(*Particle Civics*, Environmental Working Group – Sharp and Walker, p. 5.) These 9,300 deaths are 4.6 times more than victims of homicide and six times the number who die of AIDS.

[11] 'The Real Price of Gasoline', International Center for Technology Assessment (CTA), http://www.icta.org/projects/trans/rlprexsm.htm, 1999.

A report by the International Center for Technology Assessment (CTA)[12] illustrates how uneven the playing field is by spelling out the subsidies and tax breaks that affect the price of gasoline. See Table 18 for the estimates.

Table 18. Summary of Subsidies and Tax Breaks to Oil Industry

What It Is	What It Is Called	What It is Worth per Year
Subsidy	Percentage Depletion Allowance	$784 million to $1 billion
Subsidy	Non-conventional Fuel Production Credit	$769 to $900 million
Subsidy	Immediate Expensing of Exploration and Development Costs	$200 to $255 million
Subsidy	Enhanced Oil Recovery Credit	$26.3 to $100 million
Tax Break	Foreign Tax Credits	$1.11 to $3.4 billion
Subsidy	Accelerated Depreciation Allowances	$1.0 to $4.5 billion

The tax subsidies do not end at the federal level. The fact that most state income taxes are based on oil firms' deflated federal tax bill results in an estimated under-taxation of $125 to $323 million per year. Many states also impose fuel taxes that are lower than regular sales taxes, amounting to a subsidy of $4.8 billion per year to gasoline retailers and users.

Including other subsidies not cited here, CTA calculated that the annual tax breaks and subsidies that prop up the price of gasoline at the pump comes to between $9.1 and $17.8 billion. The National Defense Council Foundation (NDCF)[13], which also looked into the tax breaks and subsidies in a 2003 study, estimated lost federal and state revenues annually at $13.4 billion. These figures do not include support of US petroleum producers through program subsidies for extraction, production, and use of petroleum and petroleum fuel products, which total another $38 to $114.6 billion each year according to CTA. Furthermore, these figures do not take into account the many other external costs of oil previously cited.[14]

This uneven playing field makes difficult the success of the Hydrogen Highway Network and its potential for significant benefits to human health and our environment.

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[12] Ibid.

[13] http://www.ndcf.org/ and http://www.iags.org/n1030034.htm NDCF report: 'The Hidden Cost of Imported Oil'

[14] CTA's report categorized the hidden costs of oil as follows: (1) Tax Subsidization of the Oil Industry; (2) Government Program Subsidies; (3) Protection Costs Involved in Oil Shipment and Motor Vehicle Services; (4) Environmental, Health, and Social Costs of Gasoline Usage; and (5) Other Important Externalities of Motor Vehicle Use. They estimated the real cost of gasoline, if the external costs were added, could be upwards of $15 a gallon. This estimate was made before the recent dramatic increase in the price of a barrel of oil. (For a more comprehensive look at the hidden cost of oil, see 'The Hidden Cost of Oil' by Suzanne Klein.)

3.5 Recommendations and Next Steps

Looking ahead, we must move forward carefully to ensure that we do not choose a path that expedites implementation of the CA H2 Net at the expense of public health. To this end, we make the following recommendations:

- Localized as well as regional impacts from hydrogen production pathways must be evaluated to ensure there are no negative external impacts to local communities that may or may not already be disproportionately impacted by air pollution. Hydrogen production pathways should be chosen that significantly reduce greenhouse gases, air toxics and criteria pollutants. No pathway should be considered that will result in an increase in any of these emissions regionally or locally. An aggregate goal by itself will not address this issue. Based on emissions and heath costs externalities, pathways should be chosen that maximize the benefit to public health.

- The CA H2 Net implementation plan provides the opportunity to ensure that any incremental energy needs do not rely on coal either in California or from the power grid.

- The externalities due to petroleum based fuels and high-carbon-content fuels as well as the externalities of individual production pathways must be incorporated into all current and future discussions, analyses and decision-making.

3.6 Conclusion on Benefits of Hydrogen

Based on the studies presented, health care costs range between $5 billion and $110 billion annually in the South Coast Air Basin of California alone. As a point of comparison, cigarette smoking costs California approximately $16 billion each year in health care costs and lost productivity.[15]

Although the figures are staggering, history has proven they are not insurmountable. The World Bank calculated that the U.S. ended up saving $10 for every $1 it invested in its phase-out of lead in gasoline by reducing health care costs, saving on engine maintenance and improving fuel efficiency with modern vehicles.[16]

As the number of vehicles running on petroleum-based fuels continue to grow and air quality regulations continue to change, accurate health care cost estimates will remain subject to fluctuations and scientific limitations. One fact, however, has not changed: Due to our continued dependence on petroleum, children, elderly and disproportionately impacted lower income communities will continue to pay for the brunt of the adverse health impacts from petroleum-related uses.

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[15] Based on a January 21, 2003, posting on Healthline referencing a recent study by the University of California- San Francisco Institute of Health and Aging.

[16] "The Secret History of Lead: Special Report," The Nation-Jamie Lincoln Kitman, March 2000.

Those that ultimately guide the CA H2 Net must foster a level playing field for cleaner transportation alternatives such as hydrogen by incorporating externalities into all decision-making. These externalities help justify the investment needed to build a hydrogen highway network, and emphasize the need to appropriately subsidize cleaner alternatives that would ultimately result in significantly benefits to public health and the environment.

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STATION COST APPENDICES

- Appendix A — Summary of Costs for 10 Station Types
- Appendix B — Line Item Station Costs
- Appendix C — Assumptions
- Appendix D — Station Cost Summary: Equipment, Installation, and Operation
- Appendix E — Production Volume and Scaling Adjustments
- Appendix F — Sources of Industry Cost Data

Appendix A. Summary of Costs for 10 Station Types

Summary of Costs for 10 Station Types

	SMR 100	SMR 1000	EL-G 30	EL-PV 30	EL-G 100	MOB 10	LH2 1000	PEMES 100	HTFC 91	PIPE 100
Hydrogen Equipment	$317,981	$1,021,169	$147,301	$147,301	$250,279	$162,804	$510,049	$317,981	$365,075	$100,000
Purifier	$63,741	$201,567		$-		$-	$-	$63,741	$-	$20,000
Storage System	$218,684	$2,635,215	$57,268	$57,268	$210,449	$-	$1,102,263	$40,674	$136,126	$45,580
Compressor	$51,652	$171,113	$27,611	$27,611	$51,652	$-	$269,817	$51,652	$49,235	$93,356
Dispenser	$42,377	$127,130	$42,377	$42,377	$42,377	$-	$127,130	$42,377	$42,377	$42,377
Additional Equipment	$72,098	$77,458	$66,738	$66,738	$72,098	$10,000	$87,458	$107,098	$122,658	$72,098
Installation Costs	$193,455	$300,373	$165,408	$128,021	$228,837	$44,227	$329,858	$187,163	$192,959	$175,027
Contingency	$113,004	$624,136	$50,315	$63,583	$92,412	$25,475	$309,103	$131,461	$147,489	$55,049
Fuel Cell / Photovoltaics	$-	$-	$-	$90,000	$-	$-	$-	$268,210	$284,978	$-
Total Investment	$1,072,991	$5,158,161	$557,018	$622,898	$948,104	$242,506	$2,735,679	$942,146	$1,340,895	$603,488
Hydrogen $/yr	$-	$-	$-	$-	$-	$4,331	$713,757	$-	$-	$34,648
Delivery	$-	$-	$-	$-	$-	$806	$-	$-	$-	$-
Natural gas $/yr	$19,708	$183,941	0	$-	$-	$-	$-	$106,511	$106,511	$-
Electricity $/yr	$6,289	$63,205	$42,884	$27,254	$142,945	$-	$19,059	$(200,605)	$(200,605)	$-
Maint., Labor, Overhead $/yr	$67,689	$196,541	$34,027	$39,127	$60,705	$17,790	$168,698	$78,467	$78,467	$38,765
Total Operating Cost	$93,686	$443,687	$76,911	$66,381	$203,650	$22,928	$901,515	$(15,626)	$(15,626)	$73,413
Annualized Cost	$234,757	$1,121,850	150144.0693	$148,276	$328,301	$54,005	$1,261,185	$234,889	$160,667	$159,333
Sales Revenue $3/kg/yr	$51,973	$519,726	$15,592	$15,592	$51,973	$5,197	$519,726	$51,973	$99,645	$51,973
Annual Funding Need	$182,784	$602,124	$134,552	$132,684	$276,329	$48,807	$741,459	$182,916	$61,022	$107,361
Capcity Kg/day	100	1000	30	30	100	10	1000	100	91	100
Capacity Utilization	47%	47%	47%	47%	47%	47%	47%	47%	100%	47%
Hydrogen Sales Kg/yr	17,324	173,242	5,197	5,197	17,324	1,732	173,242	17,324	33,215	17,324

Key Assumptions: 13%

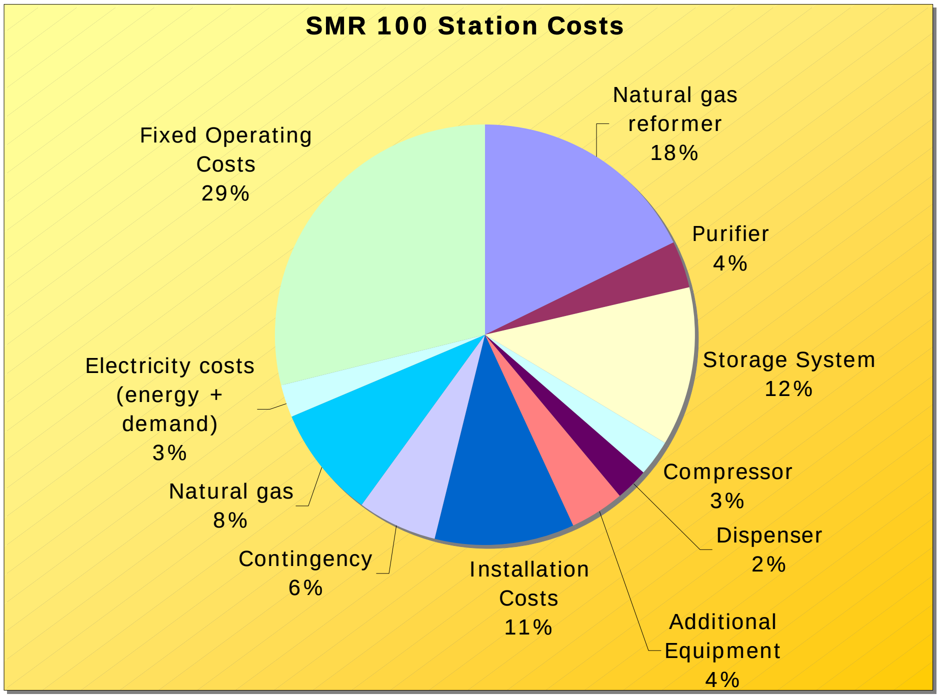
Assumes a scenario of 20,000 vehicles and 250 stations sited in 2010

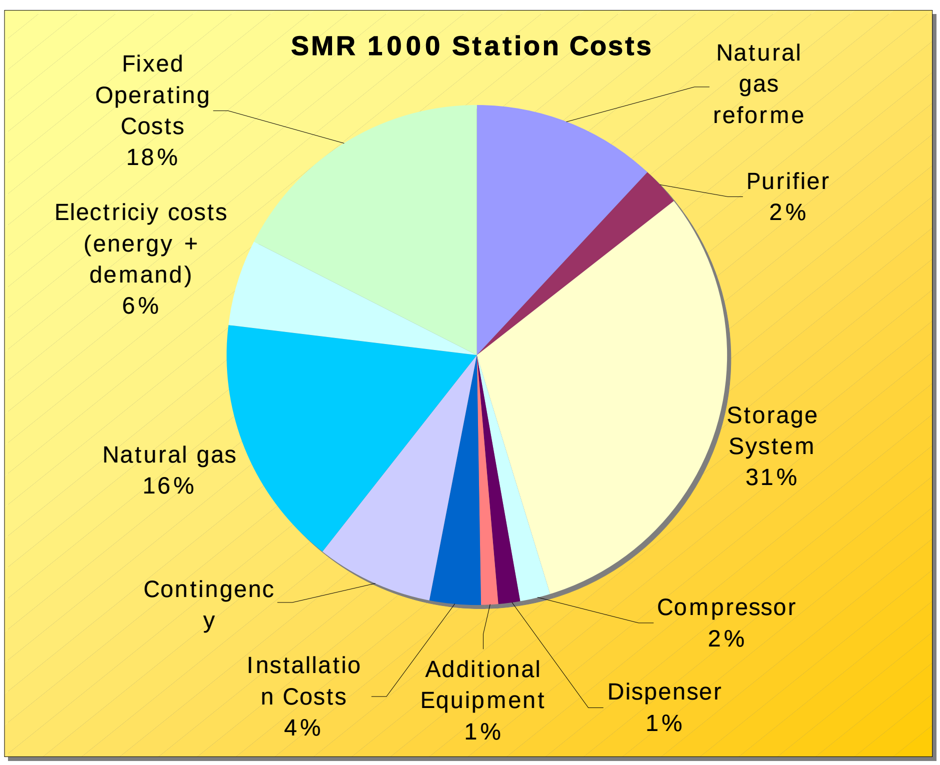
Additional equipment includes mechanical, electrical, and safety equipment

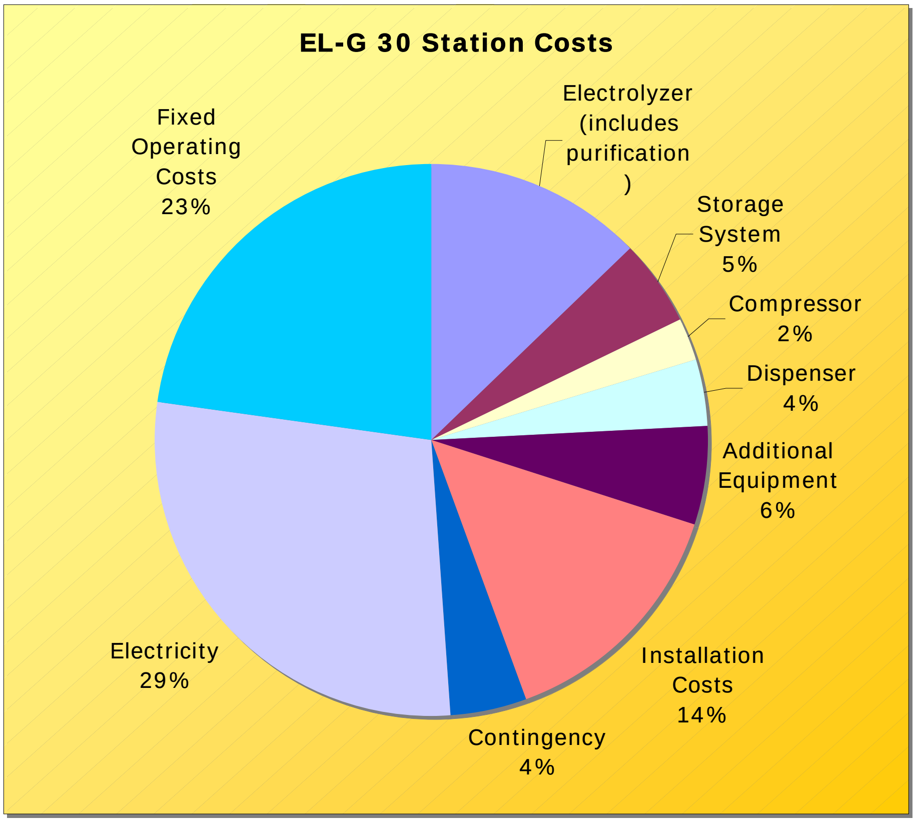
Installation Costs includes engineering and design, permitting, site development and safety & hazops analysis, installation, delivery, start-up & commissioning

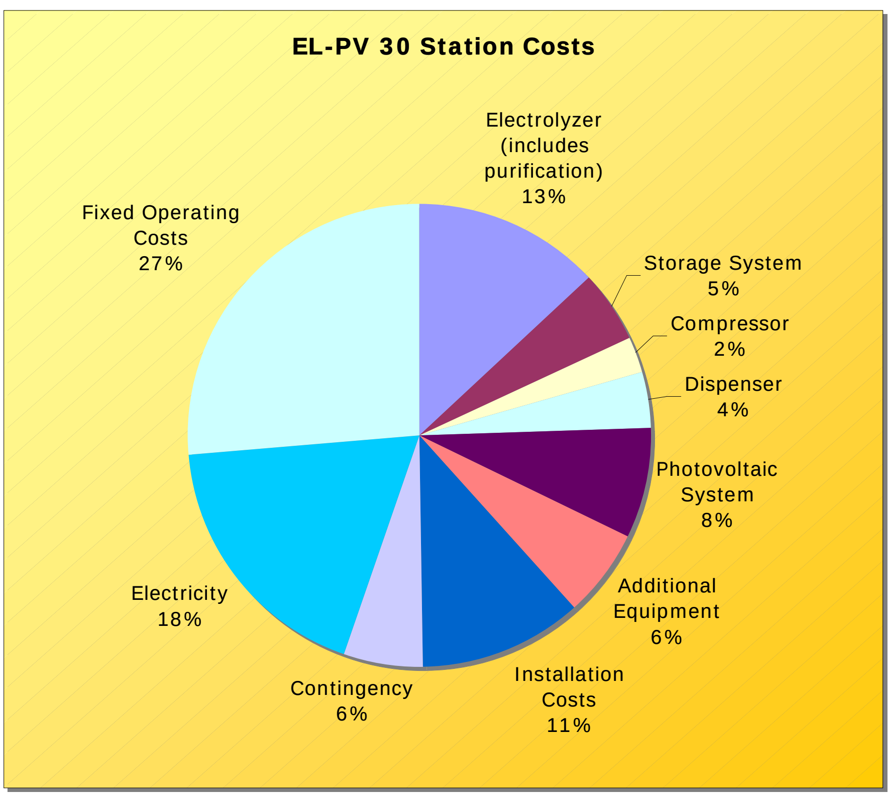
Labor and Overhead costs are maintenance, rent, labor, insurance, property tax

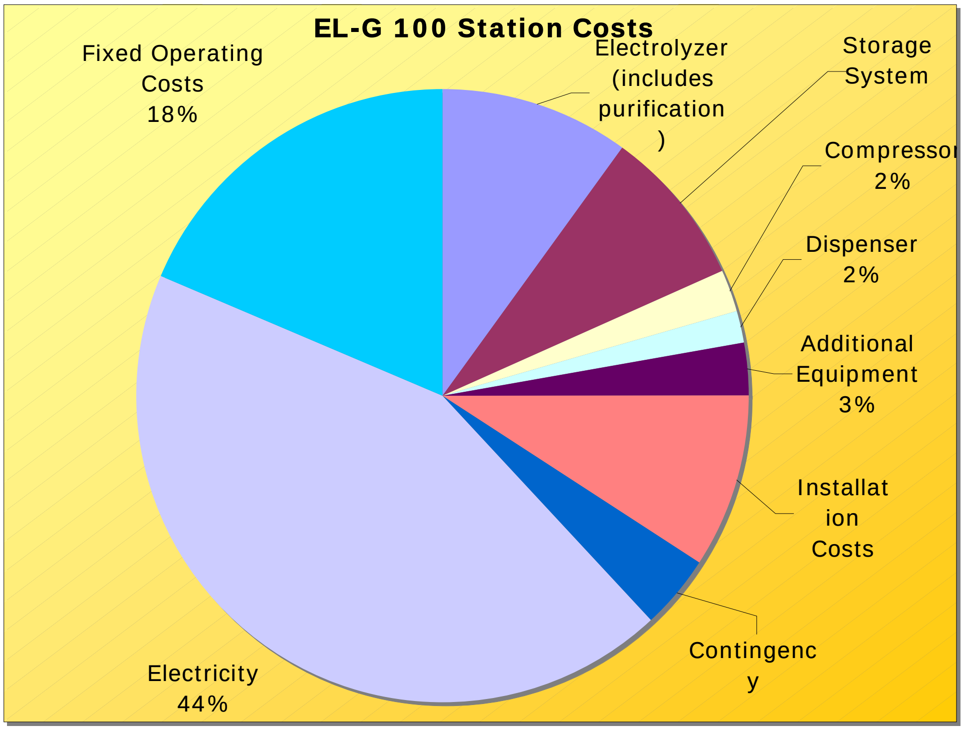
Capital Recovery factor

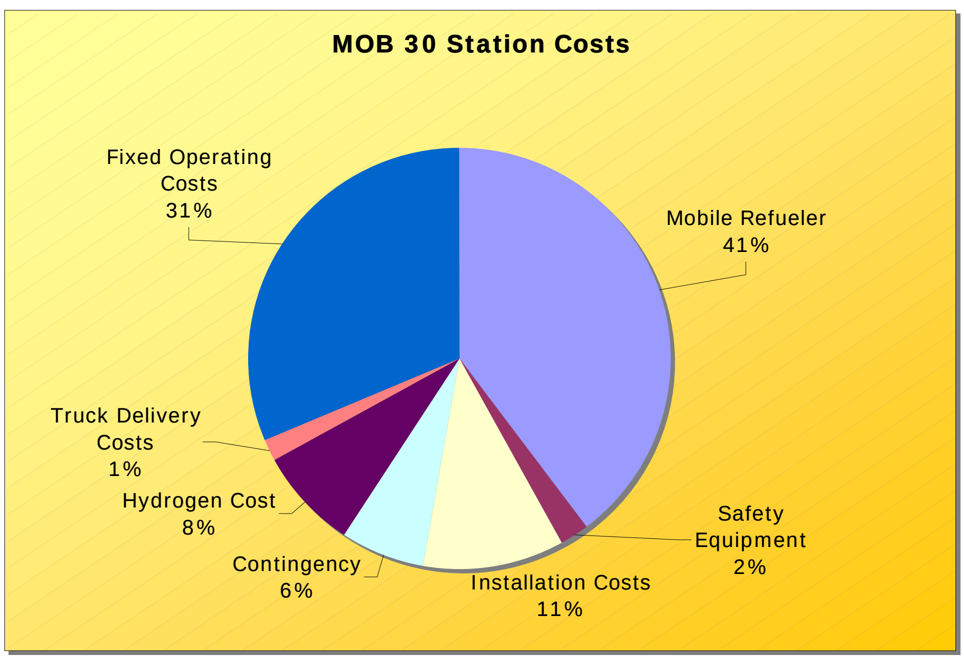

SMR 100 Station Costs
Natural gas reformer 18%
Purifier 4%
Storage System 12%
Compressor 3%
Dispenser 2%
Additional Equipment 4%
Installation Costs 11%
Contingency 6%
Natural gas 8%
Electricity costs (energy + demand) 3%
Fixed Operating Costs 29%

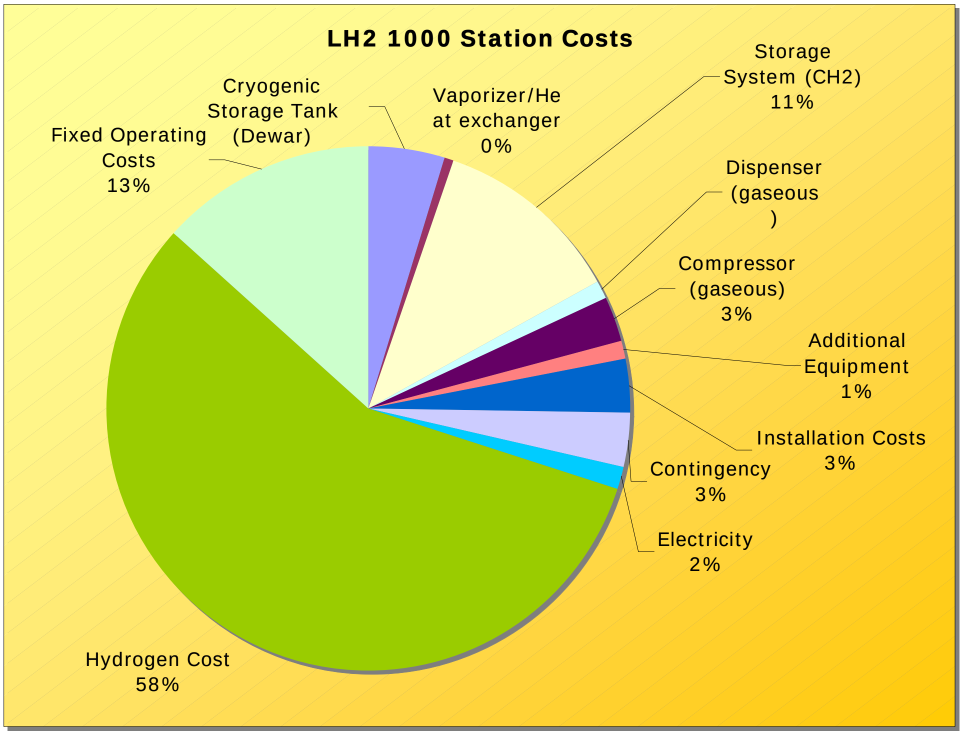

SMR 1000 Station Costs
Natural gas reforme
Purifier 2%
Storage System 31%
Compressor 2%
Dispenser 1%
Additional Equipment 1%
Installation Costs 4%
Contingency
Natural gas 16%
Electriciy costs (energy + demand) 6%
Fixed Operating Costs 18%


EL-G 30 Station Costs
Electrolyzer (includes purification)
Storage System 5%
Compressor 2%
Dispenser 4%
Additional Equipment 6%
Installation Costs 14%
Contingency 4%
Electricity 29%
Fixed Operating Costs 23%


EL-PV 30 Station Costs
Electrolyzer (includes purification) 13%
Storage System 5%
Compressor 2%
Dispenser 4%
Photovoltaic System 8%
Additional Equipment 6%
Installation Costs 11%
Contingency 6%
Electricity 18%
Fixed Operating Costs 27%


EL-G 100 Station Costs
Fixed Operating Costs 18%
Electrolyzer (includes purification)
Storage System
Compressor 2%
Dispenser 2%
Additional Equipment 3%
Installat ion Costs
Contingenc y
Electricity 44%


MOB 30 Station Costs
Fixed Operating Costs 31%
Mobile Refueler 41%
Truck Delivery Costs 1%
Hydrogen Cost 8%
Safety Equipment 2%
Contingency 6%
Installation Costs 11%


LH2 1000 Station Costs
Storage System (CH2) 11%
Cryogenic Storage Tank (Dewar)
Vaporizer/Heat exchanger 0%
Fixed Operating Costs 13%
Dispenser (gaseous)
Compressor (gaseous) 3%
Additional Equipment 1%
Installation Costs 3%
Contingency 3%
Electricity 2%
Hydrogen Cost 58%

Appendix B. Line Item Station Costs

Station 1: SMR 100

Total capital equipment costs	**$766,532**
Natural gas reformer	**$317,981**
Purifier	**$63,741**
Storage System	$218,684
Compressor	$51,652
Dispenser	$42,377
Electrical Equipment	$42,658
Safety Equipment	$10,000
Mechanical and Piping	$19,440
Total non-capital station costs	**$306,459**
Engineering (incl proj. mgt. & design)	$36,856
Permitting	$42,753
Site Development	$15,811
Safety and Haz-ops Analysis	$22,113
Equipment Delivery	$16,216
Installation	$36,856
Start-up & Comissioning	$22,850
Contingency	$113,004
Total Operating Costs ($/yr)	**$93,686**
Total Maintenance	$30,661
Natural gas	$19,708
Electricity costs (energy + demand)	$6,289
Rent for landscape and hardscape	$4,800
Labor (full-service fueling)	$4,563
Insurance	$20,000
Property taxes	$7,665
Finanacial Calculations*	
Annual Fixed Expenses ($/yr)	$93,686
Total installed station capital costs	$1,072,991
Annual Cost ($/yr)	$234,757
Hydrogen cost per kilogram	**$13.55**

Appendix C. Assumptions

Station Assumptions		
Natural gas ($/MMBtu)	7	/MMBTU
Electricity ($/kWh)	0.1	/kWh
Demand charge ($/kW/month)	$13	/kW
Capacity Factor	24%	
After-tax rate of return	10%	=d
recovery period in years	15	=n
% of labor allocated to fuel sales	50%	
Real Estate Cost ($/ft^2/month)	0.5	/ft^2/month
Contingency	20%	of total installed capital cost (TIC)
Property Tax	1%	(% of TIC)

Equipment Assumptions				
Equipment	***Type***			***Scaling Factors***
Reformer	SMR, Pressurized, 10 atm			0.6
Electrolyzer	Alkaline			0.44
Purifier	Pressure Swing Absorption			0.5
Compressor	reciprocating			0.7
Storage	carbon steel tanks, cascade system, max vessel size 3 m^3			0.8
Dispenser				0
Fuel Cell	PEM/MCFC			0.7
Mobile Refueler	includes storage, compressor, and dispenser			
LH2 Equipment	Dewar vessel and vaporizer			
Station Construction (non-capital Costs)	Inc. engineering/design, permitting, installation, etc.			
Compression energy		3	kWh/kg	
Outlet Pressure		5000	psi	
Percent of vehicles fueled in:		2	hours =	40%

Production Volume Assumptions **Scenario C**

Equipment	Current Cumm. Prod Vol. (units)	2010 Projected Prod Vol. (units)	Progress Ratio	Prod Vol Discount Factor
Reformer	4	24	85%	77%
Electrolyzer	10	114	85%	68%
Purifier	10	79	85%	73%
Compressor	100	280	90%	91%
Storage	300	934	95%	95%
Dispenser	17	215	90%	77%
Fuel Cell	5	32	85%	76%
Mobile Refueler	10	80	90%	81%
LH2 Equipment	5	12	90%	93%
Station Construction (non-capital Costs)	15	265	90%	74%

H2Hwy Network Assumptions

Scenario	A	Bf	B	C	C2
# of Stations					
LD Vehicles	2000	10000	10000	20000	20000
HD Vehicles	10	100	100	300	300
H2 Demand, tonne/yr	426	2381	2381	4762	6190
Infrstructure mix	a1+a2	a1+a2+b	a1+a2+b+c1	a1+a2+b+c1	a1+a2+b+c2
Capacity	50.0	150.0	250.0	250.0	250.0
Cap Factor	**16%**	**34%**	**24%**	**47%**	**39%**
	0	0	0	0	0
% of stations	A	Bf	B	C	C2
1. Steam Methane Reformer, 100	12.0%	12.0%	8.0%	8.0%	10.4%
2. Steam Methane Reformer, 1000	0.0%	1.3%	0.8%	0.8%	2.0%
3. Electrolyzer, grid, 30	6.0%	10.7%	6.4%	6.4%	7.2%
4. Electrolyzer, renewable energy, 30	18.0%	26.0%	27.6%	27.6%	22.4%
5. Electrolyzer, grid, 100	10.0%	5.3%	7.6%	7.6%	11.6%
6. Mobile Refueler, 10	20.0%	24.7%	28.0%	28.0%	20.0%
7. Delivered LH2, 1000	8.0%	3.3%	2.8%	2.8%	3.2%
8 & 9 Energy Stations, 100	18.0%	13.3%	14.4%	14.4%	16.8%
10. Pipeline Station, 100	8.0%	3.3%	4.4%	4.4%	6.4%
	100.0%	100.0%	100.0%	100.0%	100.0%
# of stations	A	Bf	B	C	C2
1. Steam Methane Reformer	6	18	20	20	26
2. Steam Methane Reformer	0	2	2	2	5
3. Electrolyzer, grid	3	16	16	16	18
4. Electrolyzer, renewable energy	9	39	69	69	56
5. Electrolyzer, grid	5	8	19	19	29
6. Mobile Refueler	10	37	70	70	50
7. Delivered LH2	4	5	7	7	8
8 & 9 Energy Stations	9	20	36	36	42
10. Pipeline Station	4	5	11	11	16
	50	**150**	**250**	**250**	**250**

Appendix D. Station Cost Summary: Equipment, Installation, and Operation

Station 1: Steam Methane Reformer, 100 kg/day

		$	$/yr
Natural gas reformer	17.8%	$317,981	
Purifier	3.6%	$63,741	
Storage System	12.2%	$218,684	
Compressor	2.9%	$51,652	
Dispenser	2.4%	$42,377	
Additional Equipment	4.0%	$72,098	
Installation Costs	10.8%		$193,455
Contingency	6.3%		$113,004
Natural gas	8.4%		$19,708
Electricity costs (energy + demand)	2.7%		$6,289
Fixed Operating Costs	28.8%		$37,028
Total	100%	**$766,532**	**$369,484**

Station 2: Steam Methane Reformer, 1000 kg/day

		$	$/yr
Natural gas reformer	12.0%	$1,021,169	
Purifier	2.4%	$201,567	
Storage System	30.9%	$2,635,215	
Compressor	2.0%	$171,113	
Dispenser	1.5%	$127,130	
Additional Equipment	0.9%	$77,458	
Installation Costs	3.5%		$300,373
Contingency	7.3%		$624,136
Natural gas	16.4%		$183,941
Electriciy costs (energy + demand)	5.6%		$63,205
Fixed Operating Costs	17.5%		$111,868
Total	1.00	**$4,233,652**	**$1,283,523**

Station 3: Electrolyzer-grid, 30 kg/day

Electrolyzer (includes purification)	12.9%	$147,301	
Storage System	5.0%	$57,268	
Compressor	2.4%	$27,611	
Dispenser	3.7%	$42,377	
Additional Equipment	5.8%	$66,738	
Installation Costs	14.5%	$165,408	
Contingency	4.4%	$50,315	
Electricity	28.6%		$42,884
Fixed Operating Costs	22.7%		$34,027
Total	$1	**$557,018**	**$76,911**

Station 4: Electrolyzer-solar, 30 kg/day

		$	**$/yr**
Electrolyzer (includes purification)	13.1%	$147,301	
Storage System	5.1%	$57,268	
Compressor	2.4%	$27,611	
Dispenser	3.8%	$42,377	
Photovoltaic System	8.0%	$90,000	
Additional Equipment	5.9%	$66,738	
Installation Costs	11.4%	$128,021	
Contingency	5.6%	$63,583	
Electricity	18.4%		$27,254
Fixed Operating Costs	26.4%		$39,127
Total	100%	**$622,898**	**$66,381**

Station 5: Electrolyzer-grid, 100 kg/day

		$	$/yr
Electrolyzer (includes purification)	10.0%	$250,279	
Storage System	8.4%	$210,449	
Compressor	2.1%	$51,652	
Dispenser	1.7%	$42,377	
Additional Equipment	2.9%	$72,098	
Installation Costs	9.2%	$228,837	
Contingency	3.7%	$92,412	
Electricity	43.5%		$142,945
Fixed Operating Costs	18.5%		$60,705
Total	100.0%	**$948,104**	**$203,650**

Station 5: Electrolyzer-grid, 100 kg/day

		$	$/yr
Electrolyzer (includes purification)	10.0%	$250,279	
Storage System	8.4%	$210,449	
Compressor	2.1%	$51,652	
Dispenser	1.7%	$42,377	
Additional Equipment	2.9%	$72,098	
Installation Costs	9.2%	$228,837	
Contingency	3.7%	$92,412	
Electricity	43.5%		$142,945
Fixed Operating Costs	18.5%		$60,705
Total	100.0%	**$948,104**	**$203,650**

Station 6: Mobile Refueler, 10 kg/day

		$	$/yr
Mobile Refueler	39.6%	$162,804	
Safety Equipment	2.4%	$10,000	
Installation Costs	10.8%	$44,227	
Contingency	6.2%	$25,475	
Hydrogen Cost	8.0%		$4,331
Truck Delivery Costs	1.5%		$806
Fixed Operating Costs	31.4%		$17,790
Total	100.0%	**$242,506**	**$22,928**

Station 6: Mobile Refueler, 10 kg/day

		$	$/yr
Mobile Refueler	39.6%	$162,804	
Safety Equipment	2.4%	$10,000	
Installation Costs	10.8%	$44,227	
Contingency	6.2%	$25,475	
Hydrogen Cost	8.0%		$4,331
Truck Delivery Costs	1.5%		$806
Fixed Operating Costs	31.4%		$17,790
Total	100.0%	**$242,506**	**$22,928**

Station 8: PEM/Reformer Energy Station, 100 kg/day

		$	$/yr
Natural gas reformer	17.8%	$317,981	
Purifier	3.6%	$63,741	
Storage System	2.3%	$40,674	
Compressor	2.9%	$51,652	
Dispenser	2.4%	$42,377	
PEM Fuel Cell	15.0%	$268,210	
Additional Equipment	6.0%	$107,098	
Installation Costs	10.5%	$187,163	
Contingency	7.4%	$131,461	
Electricity costs (energy + demand)	-16.2%		$(37,961)
Natural gas	15.9%		$37,370
Fixed Operating Costs	32.5%		$76,349
Total	100.0%	**$1,210,356**	**$75,759**

Option 9: MCFC Energy Station, 100 kg/day

		$	$/yr
Natural gas reformer	29.9%	$365,075	
Purifier	0.0%	$-	
Storage System	11.1%	$136,126	
Compressor	4.0%	$49,235	
Dispenser	3.5%	$42,377	
MC Fuel Cell	23.3%	$284,978	
Additional Equipment	10.0%	$122,658	
Installation Costs	15.8%	$192,959	
Contingency	12.1%	$147,489	
Electricity costs (energy + demand)	-124.9%		$(200,605)
Natural gas	66.3%		$106,511
Fixed Operating Costs	48.8%		$78,467
Total	100.0%	**$1,340,895**	**$(15,626)**

Station 10: Pipeline Station, 100 kg/day

		$	$/yr
Connection to Main Pipline	8.4%	$100,000	
Storage System	3.8%	$45,580	
Compressor	7.9%	$93,356	
Dispenser	3.6%	$42,377	
Additional Equipment	6.1%	$72,098	
Installation Costs	14.8%	$175,027	
Contingency	4.4%	$52,101	
Electricity costs (energy + demand)	3.8%		$5,977
Hydrogen (from pipe)	22.3%		$34,648
Fixed Operating Costs	24.9%		$38,765
Total	100.0%	**$580,540**	**$79,391**

Appendix E. Production Volume and Scaling Adjustments

Scaling and Production Volume Adjustment of Industrial Data

(yellow)	=industry data
(yellow, underlined)	= adjusted data
(green)	= assumption

Industry Data on SMR Reformers

			kg/hr	units/yr	kg/hr	units/yr
			4.2	4	42	1
Capacity (kg/hr)	Production Volume (units/yr)	Total Cost ($2004)	Total Cost: (Size Scaled)	Total Cost (PV Scaled)	Total Cost: (Size Scaled)	Total Cost (PV Scaled)
1.5	2	$372,000	$686,691	583,687	2,733,767	1,874,465
4.16	2	$400,000	$400,384	340,327	1,593,959	1,092,932
6.25	2	$200,000	$156,811	133,289	624,274	428,047
9	2	$1,116,000	$703,059	597,600	2,798,929	1,919,145
		AVERAGE	486,736	**413,726**	1,937,732	**1,328,647**
		Standard Deviation		$221,155		$710,222

Industry Data on Alkaline Electrolyzer

			kg/hr	units/yr	kg/hr	units/yr
			1.25	10	4.17	10
Capacity (kg/hr)	Production Volume (units/yr)	Total Cost ($2004)	Total Cost: (Size Scaled)	Total Cost (PV Scaled)	Total Cost: (Size Scaled)	Total Cost (PV Scaled)
3.43	2	$686,044	$440,011	301,703	747,623	512,623
1	2	$161,116	$177,738	121,870	301,995	207,069
1.3	1	$370,000	$357,856	208,565	608,033	354,374
2.7	1	$450,000	$320,823	186,982	545,111	317,702
5.4	1	$670,000	$352,107	205,215	598,265	348,681
1.3	10	$250,000	$241,794	241,794	410,833	410,833
2.7	10	$310,000	$221,011	221,011	375,521	375,521
5.4	10	$450,000	$236,490	236,490	401,820	401,820
		AVERAGE	$293,479	**$215,454**	$498,650	**$366,078**
		Standard Deviation		$51,168		$86,939

Industry Data on Purifiers			kg/hr 4.17	units/yr 10	kg/hr 41.7	units/yr 10
Capacity (kg/hr)	Production Volume (units/yr)	Cost (2004$)	Total Cost: (Size Scaled)	Total Cost (PV Scaled)	Total Cost: (Size Scaled)	Total Cost (PV Scaled)
3	2	$100,000	$117,898	80,839	372,827	255,637
9	2	$200,000	$136,137	93,345	430,504	**295,184**
		AVERAGE		**87,092**		**275,410**
		Standard Deviation		$8,843		$27,964

Appendix F. Sources of Industry Cost Data

Sources of Industry Cost Data:

TIAX
Air Products
BOC
BP
Cal State University LA
Chevron Texaco
Clean Energy
Dynetek
FIBA
Fuel Cell Energy
Fueling Technologies Inc.
H2Gen
Harvest Technologies
Hydrogenics
HydroPac
ISE Research
Nippon Oil
PDC Machines
Praxair
Pressure Products Industries
Proton Energy
Quantum Technologies
SCAQMD
Stuart Energy
Toyota
Ztek

Appendix G. Market-Based Incentives for Distributed (Including Hydrogen-Based) Power Generation

Background: The need for reforms to encourage utilities and state Public Utility Commissions (PUCs) to more actively support distributed generation is based upon three basic themes. First, end users have a growing need for higher reliability power than can be obtained from the grid. There are inherent limitations on distribution reliability, such as weather, accidents, and disturbances, that cannot be entirely overcome with better generation or transmission. The need for the highest level of reliability can only be met with devices installed at the customer end of the wire. Second, utilities need encouragement, perhaps even pressure, to embrace the idea of expanding the definition of distribution service to include onsite facilities. Third, a variety of technologies and products, including combustion-based, battery-based, flywheel-based technologies, are commercially proven for these applications. Hydrogen systems are near commercial readiness for serving these needs, though their costs may be high and in many cases their reliability is not proven.

Many utilities are of the view that they could not install/own such systems at their customers even if they wanted to because "deregulation has barred them from the generation business." A number of states bar distribution utilities from generation, but that is in the context of wholesale market purchasing. Distributed generation, on the other hand, tends to be a much smaller scale generation that serves the purpose of enhancing the quality of fundamental distribution service.

So here is the basic proposal:

A Proposed Market-Based Incentive For Distributed (Including Hydrogen-Based) Power Generation

1. Create a new rate class—uninterruptible service. End users would have the right to demand this service from their utility. The service would be supported by contracts and facilities that establish the rights and obligations (including damages for interruption) of the parties. In principle, this service would require the installation of new facilities at the customer's location. Actual rates would be contract-based and would not affect the cost of any other service for any other customer. Utilities gain the opportunity to create a new source of investment and return. Regulators would neither reward nor penalize utilities for engaging in this business; it is entirely contractual between the end user and the utility provider.

2. Once a utility has provided a contractual offer in response to an end user's request for this service, the customer would be entitled to obtain this service from other third parties. In return for the utility being given the first opportunity to create this new market, it takes on the obligation to provide full and open access between the user and all relevant distribution facilities. Any upstream costs that need to be incurred in order to affect service need to be made part of the utility's contract offer (again, in order to avoid any cross subsidy issues). [*Would the utility choose the third-party*

equipment installer? If not, it's hard to see why the utility would want to take responsibility for something they don't control – especially is it involves safety or liability.]

3. Regulators would be empowered to review any complaints by end users that the scope and cost of proposed uninterruptible service is unreasonable. If proposed interconnection facilities and costs are seen as excessive, regulators could scale back the scope of such facilities. [*For safety and reliability issues, as well as contractual issues, the utilities would really need to be involved with interconnection.]* (This gives regulators something to do, while assuring a fair and open system for new players.) The utility would not be allowed to charge any third party service provider for any costs not included in its own proposal to the end-user. [*What if the installation agreed between the customer and the 3rd-party installer was done poorly or the equipment was defective?]*

The net result is a system that provides higher quality service and is more open to providers of new products and technologies. It removes a very real disincentive to new distributed generation technologies making their way into today's utility environment, but does so in a manner that gives the utility a positive incentive to participate in that new wave of technology. Ultimately, a utility environment characterized by a mix of central generation and an array of distributed resources is more reliable for everyone.

Appendix H. Franchise Concepts

A franchise is a method a company uses to distribute its products or services through retail outlets owned by independent, third party operators. The independent operator does business using the marketing methods, trademarked goods and services and the "goodwill" and name recognition developed by the company. In exchange, the independent operator pays an initial fee and royalties to the owner of the franchise.

The company that grants the independent operator the right to distribute its trademarks, products, or techniques is known as the franchisor. The independent, third party business person distributing the franchisor's products or services through retail or service outlets is called the franchisee.

Franchise offerings must comply with federal regulations, and, in some cases, with even tougher state regulatory laws. Some states do not require registration based upon the net worth of the franchisor or if the franchisor has a federally registered trademark.

There are three basic types of franchises:

- Distributorships, which grant the right to sell their parent company's product(s) such as auto dealerships.
- Trademark or brand name licensing, which gives the licensees the right to use the parent company's trademark or brand in conjunction with the operation of their own business i.e. beverages (e.g. Coca-Cola) and sport franchises (NFL, MLB, , etc).
- Business format franchises, the type most people are familiar with (Subway, Meineke Muffler, Circle K).